BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- -x

IN THE MATTER OF: :

PJM INTERCONNECTION, LLC : Docket Numbers

TECHNICAL CONFERENCE - COMPENSATION FOR : PL04-2-000

GENERATING UNITS SUBJECT TO LOCAL MARKET :

POWER MITIGATION IN BID-BASED MARKETS :

- -x

Hearing Room 2C
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C.
Wednesday, February 4, 2004

The above-entitled matter came on for technical conference, pursuant to notice, at 9:10 a.m.

BEFORE:

MICHAEL COLEMAN, presiding

OMTR

APPEARANCES:

FRANK NAPOLITANO, Lehman Brothers Inc.

JONATHAN BALIFF, Credit Suisse First Boston Corporation

MICHAEL THOMAS, Calpine Corporation

WILLIAM HOGAN, Harvard University

MICHAEL SCHNITZER, The NorthBridge Group, representing Exelon Corp.

ROY SHANKER, Consultant to generators & Financial market participants

DAVID PATTON, Potomac Economics, MISO Market Monitor

JOE BOWRING, PJM Market Monitor

ROY THILLY, Wisconsin Public Power Inc.

ABRAM KLEIN, Edison Mission Marketing & Trading

JOHN ANDERSON, John Hancock Financial Services

JONATHAN BALIFF, Credit Suisse First Boston Corporation

MARK REEDER, New York Public Service Commission

STEVE CORNELI, NOG Power Marketing Inc

BOB ETHIER, ISO-NE Market Monitor

GUNNAR JORGENSEN, Northeast Utilities/Select Energy

HOWARD NEWMAN, Warburg Pincus

DANIELLE JASSAUD, Public Utility Commission of Texas

JOHN MEYER, Reliant Resources, Inc.

JUDI MOSLEY, Pacific Gas & Electric Company

KEITH CASEY, CAISO

-- continued --

APPEARANCE CONTINUED:

STEVE BEUNING, Xcel Energy

RON MCNAMARA, MISO

P R O C E E D I N G S

(9:10 a.m.)

MR. COLEMAN: Good morning. Welcome to the Technical Conference in Docket PO04-2, Compensation for Generating Units Subject to Local Market Power Mitigation bid-based markets. I'm Michael Coleman of FERC Staff. I'm the moderator for today's conference.

The purpose of today's technical conference is to engage industry experts and market participants in a meaningful dialogue on the issue of appropriate compensation for generation subject to local market power mitigation.

The issue was formally teed up in a PJM docket last year. The concern, however, is not limited to PJM. All regions of the country have local transmission-constrained areas where generation owners can exercise local market power due to concentration of ownership and generating units in that area where the uniqueness of a specific generating unit can solve a local reliability problem.

We will hear today about how these situations arise, what steps have been taken to date to mitigate prices paid to such generators, what further needs to be done to resolve RMR problems, who should be responsible for implementing solutions, and who pays.

There are many different solutions that are appropriate for different regions or different fact patterns. There may be options for the same area. The solutions may vary from improving the market design and pricing, to incentives to attract and retain infrastructure solutions to auctions to identify the most effective and efficient infrastructure and response.

That's a lot of ground to cover, so let me lay out a few logistics: Conferences are being held today and tomorrow. Today will be a broad overview of principles, the pricing arm of units across the country.

Tomorrow will be a more granular discussion of the proposals in the PJM EL03-236 docket. We have a full house and a packed agenda today, with an oversubscription of speakers.

This basically reflects the interest in and the importance of the RMR issue. To accommodate those who were unable to present today, we are allowing parties to file comments in the PL04-2 docket. We ask that those comments be filed by February 27th. We'll probably issue a notice sometime later on this week. That will formally indicate a February 27th comment date.

The technical conference is being transcribed, and we will let you know when the transcript is available.

Today's agenda and format: This morning we have an opening presentation on capital formation for power infrastructure. Many of the long-term solutions for RMR issues we're likely to hear about today involved infrastructure additions, and the ability to attract investment in such infrastructure will be key to those solutions.

After a couple of speaker comments to supplement the presentations and perhaps a question or two, we will immediately move to our second panel for opening remarks. To allow sufficient time for an interactive discussion, we've asked speakers to limit their remarks to five to seven minutes.

A clock is provided to assist you and me in time management. Please help me out on this one. We'll take a 15-minute phone and restroom break at about 10:30. After that break, we'll convene with Q&A until the lunch break, which is scheduled from 12:15 to 1:30. The afternoon session will follow the same format as the morning. The first afternoon session will begin at 1:30 and will focus more on Northeast market experiences with local market power mitigation.

We'll take a 15-minute phone and restroom break at the conclusion of the first panel in the afternoon, and start up again at 3:30 for the second panel, which will address RMR issues and experiences in other parts of the country, including Texas, California, and the Midwest ISO region.

With that, I'd like to turn the floor over to Frank Napolitano of Lehman Brothers, for an opening presentation. Frank is manager and co-head of Lehman Global Power Group, and has graciously accepted our invitation to provide us with a short introductory presentation. Frank, welcome.

MR. NAPOLITANO: Thank you, and good morning. I have a slide presentation here of four or five pages. The intent is to provide a framework for a discussion, and it will be a bit of a review of the past, and it will bring out some observations that we at Lehman Brothers are seeing in the markets today, particularly around financing infrastructure.

It will probably not delve as deep into the load-pocket issue as many of the other, more technical speakers will go into, but we will be happy to field some Q&A on those.

(Slide.)

MR. NAPOLITANO: Starting on page 1, you see four stacked bar charts that describe four regimes I'd like to lay out here as the framework for the discussion. Regime A, all the way on the left, is meant to demonstrate the composition of a traditional utility, cost of service capital structure.

These numbers can be debated, plus or minus, but, in general, roughly 50 percent of the capital structure would be represented as debt. That debt would be considered recourse and corporate in nature.

Around five percent of the capital structure, plus or minus, is generally preferred, and around 45 percent of the capital structure is common equity. This is viewed by investors -- the perceived degree of relative risk of this regime versus the rest on the page, this is kind of viewed as the lowest-risk regime, and that capital structure demonstrates that risk.

The next regime that I demonstrate here is what is called the contracted regime. I call it the PURPA Contracted Power Project Regime.

MR. PERLMAN: Frank, your slides are not showing up. Maybe you can describe very briefly, what you're talking about, as well as describe it. They're not showing up on the screen for the audience.

MR. NAPOLITANO: We have handouts as well. In Regime B, this shows what the strength of a contract, a rateable contract that is viewed by the markets as a creditworthy instrument, what this does to the capital structure, as you look at relative risk, and as you can see from this stack bar chart, roughly 80 to 90 percent of the capital structure of a project financed off the basis of a revenue contract that I just described, could be debt.

That debt in this case is non-recourse and project finance. This is different from recourse and corporate debt. This is highly specific debt, where the payback on that debt, the return on and of the capital of debt is wholly dependent upon the operations of the project and the revenue that the contract generates.

The remainder of the capital structure in these circumstances was typically equity. As folks remember, these PURPA contracts are kind of old and cold at this point, but the long-term nature of those contracts still survives. Many of those contracts are still operative in nature, and many of the projects that were financed using these contracts, have seen a fair amount of appetite in the M&A market over the past two years as financially distressed parties look to raise capital in the most efficient way within their means.

What they found was that the value of these assets backed up by these contracts, in some cases were more valuable to them in a sale context than selling their own corporate securities, either debt or equity, to the extent they had liquidity in the markets to sell those corporate securities.

The next regime that I describe here on this chart, I call Regime C. This is kind of the highest regime risk on the page.

This is really meant to illustrate the EWG Merchant Power Projects, largely gas-fired generators, green-field, and construction in nature, that were financed during the boom times of the power market, leading up to the energy crisis.

Typically, these projects did not involve long-term contracts; they involved merchant revenue streams that the market, both debt and equity, need to become comfortable on with respect to what the composition of those streams would be.

A fair amount of expertise was brought to bear in the financing of these projects through the use of consulting reports and other types of measures to educate the investor base as to what a reasonable view of revenue could and should be.

However, the key point was that there were no underlying contracts to provide a floor to those estimations, so this was real risk. As you can see from the capital structure of these projects, ironically, a fair amount of non-recourse and project debt was available in the market at that time to finance projects of this nature, and the remainder of the capital structure is equity. We kind of list 60 to 80 percent debt against merchant power plants during those time periods.

This showed that the market at that point in time, the financing markets, were willing to buy into market development through the merchant stratification of the markets, opening of markets, many, many concepts that were seeking to be employed from a policy perspective.

The financing markets showed they were willing to sort of buy into that structure, however, the crisis involved a turn, and folks learned what the nature of merchant versus contract really meant. The folks who learned the most in that story were the debt providers. We'll talk about that more in a moment.

Largely, my remarks, as you will see, are from the debt perspective. Equity, in my view, is a derivative of the risk debt is going to take. This leads us to Regime D.

Here we are in a post-energy crisis environment. This conferences is about new infrastructure investment in selected cases. Where will the capital markets draw the line with respect to a capital structure and/or any capital flowing into these circumstances?

I will refer to these various regimes on the following pages. I'm now turning to page 2.d

This slide is entitled Assorted Financing: Lessons Learned. During Regime C, the risky part of the market, this risk can be very long; it can be very pointed.

We tried to capture some of the larger items here.

As I mentioned, this concept of buying into, there were several assumptions and parameters that were assumed to be balanced, but were tested under duress and found to be flawed.

In general, some of the categories are as follows: Disclosure. This is a very broad word. What can it mean to something in particular, like merchant power financing?

Well, it really relates to the second item, which are in our consulting reports on commodity price dynamics. If you were an investor and looked at the scope of some of these reports, you may have believed that that scope encompassed every risk that you should be knowledgeable about and possibly provided mitigants and understandings of those risks.

That, in all cases, wasn't necessarily the case, so you could argue that the universe of investors did not have a full and transparent view of the risks that they faced as to market development risk and the onset of many of these financings.

Many of the various markets, both regionally and nationally, were at their incipient stages. They had not been tested under duress. There had not been a long track record of workability under those markets. And as we have learned in California and other places, market development risk was a real investment risk that many may not have thought was a real risk at the time of those investments.

When you look at the composition of the capital structure for a typical merchant power plant under Regime C and you saw all of that non-recourse project financed debt, and then we've learned now, post-crisis, what risk that debt really took, you could assume that that debt assumed an equity level of business risk within the capital structure. I think that's a valuable lesson learned. That will certainly be on the minds of debt investors as they go forward and think about new investments.

There was a concept, however, in the industry, both the market participants, i.e., folks building infrastructure, and those financing it, that there would be some nature of self-regulatory aspects to capital flowing into infrastructure investments.

I had heard from folks that the capital markets will never let a bubble be built. Clearly, that was not the case. So, depending upon that self-regulatory nature of capital, was not a very good assumption.

There was a further assumption that bankruptcy in the utility sector was a far-off concept, one that could not actually be realized. We have learned that in not just utilities, broadly, but power, more broadly, bankruptcy is a real phenomenon; it can really happen; it really has, and it could again.

And so there is no big brother that would step into something like a public policy infrastructure situation to sort of call a time-out and stop some circumstances from happening. Those circumstances happen. Debt investors now know that, as do equity investors, and folks are aware of that situation.

The concept of non-recourse debt versus recourse -- non-recourse, again, very specific to the infrastructure being invested in. What folks have learned, post-crisis, is that non-recourse really means that debt owners can now be equity owners upon a bankruptcy type situation.

Under these circumstances, debt investors who invested non-recourse and possibly thought there might be some future infusions of capital, although none were required or mandated, but they thought that might be the case, now know that folks are going to act in their economic best interests when tested under duress.

Under these circumstances, these debt investors are now, in the case of merchant power plants, in particular, asset owners. That's a new transition within the sector.

There's a new owner base within the power sector. Clearly, those investors are not meant to be long-term owners of infrastructure capital, at least not in that method.

Lastly, really, this is a financial mechanism, but liquidity facilities -- I mentioned before about liquidity that might flow voluntarily into a non-recourse situation. In many cases, had some of the owners of those plants, the equity holders, wanted to do that, they found out that they didn't have the money themselves; they weren't getting it from free cashflow from operations, and they couldn't get it from additional lending facilities, from institutions. So they had no choice in some cases but to walk away from their equity.

One of the lessons learned, again, is that there is really no good substitute for traditional liquidity facilities in the event that additional cash is required to be injected into systems.

Page 3, Implications for Future Infrastructure Investment: Really, Bar D, where will the market draw the line with respect to new capital flowing into these situations? There are some real-world things we have deal with.

The pain amongst many of these financing players is still fresh. It's not old. We may argue that the markets may have stabilized for the time being, both from a financial and a fundamental standpoint, but the pain is still fresh and the historical, institutional investors -- which are the bank markets and the long-term fixed income markets -- they have long memories. They sort of remember what's happened here, and they remember privatizations in foreign countries where they experienced very similar characteristics with respect to their investments so close to the onset of a new market and folks are wary.

There are new players and some non-traditional players. This is smart or hot money, as it may be called on the street. These are private equity players, hedge funds and other forms of private capital.

These are folks who are opportunistic. They have liquidity; they have a desire to play where there's an opportunity with respect to a need for something as fundamental as infrastructure, and a lack of possible willing capital or capital that is priced for the large-risk premium to flow into those circumstances.

What these folks have, to their advantage, is the hindsight for those things that have recently gone wrong, and it's clear that they are going to be cognizant of those as they think about making their next investments. The market, in general, is probing for workable models of the past.

You hear "back to basics" in so many different ways. You hear it in the investment paradigm of capital flowing into infrastructure. You hear it from the management of companies that reside in the sector and are players, the owners of the assets in the sector.

And you really hear it from a market standpoint as to I want to understand how this market works. Is it transparent enough that I can observe this market working in the way you're saying that it's working, so that I can monitor the performance of my investment, either a physical investment or a financial investment?

And, lastly, there is money available to the sector. You may hear that from other speakers throughout the course. That money, as we talked about, has the advantage of an educated past, a recently-educated past, and it's able to evaluate risk and return right now.

Where does it feel most comfortable, and where will its costs be released with respect to financing? Clearly, where things are most certain: There are many,

many thoughts in the sector about what do we do now with respect to disparate markets and jurisdictional imbalances?

The left side of the spectrum is to bring it all back to where it was; the right side of the spectrum is, force it into all open and capital can be priced accordingly within that spectrum.

The clear question, though, is time. The more certain things are made, sooner, the more quickly capital will flow in a rateable fashion, and the sooner, possibly, some of these fundamental technical issues, these asset issues, can be resolved.

To the extent that the markets, as they are designed, will continue to have an implied level of risk and possibly not clear and transparent risk, capital will eventually flow, but it may cost more than it should for a certainty that may be eventually be reached at some future point in time.

I talk about optionality here, and this may be too technical for this broad of an audience, but I'll give a go at it. Capital feels comfortable with the prospects of investing in an asset which displays characteristics of a deep-in-the-money intrinsic option.

Optionality has two characteristics to it: Extrinsic, which is volatile, and, some could say, veritable; and, market-based and intrinsic, which is certainty. The most certain form of a revenue stream, as I mentioned before, is that which can raise the most debt, which is very cheap cost of capital in today's market, that's a contract.

Some assets resemble contracts in nature, fundamentally something like a low-cost coal plant in a gas marginal region. That can look like a contract. It's going to be evaluated; it's not as good as a contract, but it can look like one, something like a cost-of-service rate base that might have some performance-based up sides. That looks like Regime A, something like a contract.

Lastly, jurisdictionally undisputed, bilateral contracts where there is no argument to the validity of the contract. Well, that's a contract and that's certain. What we are saying is that the near-term balance will favor the flow of capital against where there is transparency and certainty.

Slide 4, I guess, is a layman's way of trying to talk about the complexity of what an investor may see in something like a load pocket, especially a wholesale load pocket. There's a wide degree of generation participants in that market, both the fuel type and the nature of their assets and how it meets load-serving needs

There are also things that pop into the mix like peaking generation, whether it's market-based or just built by an incumbent, and that incumbent might have the advantage of tax-exempt debt. There are things like distributed generation, combined heat and power renewables, which are somewhat social programs, but valid, and in the market, that needs to be understood.

On the transmission side, there's intragrid situations and intergrid, meaning the connection of grids to make regionality greater, the concept of super regions, and all of these assets right now, from a financing market standpoint, are kind of in play.

Whether there are existing assets suitable for the M&A market, which would involve somebody needing to finance that M&A transaction, or whether they are new - build, requiring new construction within the pocket, or whether they are going to be contributed possibly, the in the case of transmission, to some greater whole, all of those have financial implications to the current asset owners, to the new asset owners, and to how the capital structure of the various participants in that pool are constructed and how the capital will then behave.

So, it's fairly complex. You have parties who are clear entrepreneurs and profit-incented, and you have parties who are not necessarily profit-incented, but reliability-incented and subsidized with cheaper capital.

All of that sort of stirred around in one soup where the question is then put before the house, to the entrepreneurs or the companies which are entrepreneurs by nature: How do you then come and participate in the next asset-based solution? That is just quite difficult to navigate.

The last page really goes back to Regime B, which we consider to be the time-proven financing method for these types of initiatives. If you look at bilateral PURPA contracts, the way they were constructed, they generally separated fixed and variable components, not unlike gas pipelines.

And the fixed component was meant to cover certain items, and the variable component was meant to cover off certain items. The financing markets generally viewed that as a rate base and financed it as such, but it favored an arbitrage of debt over equity.

When you looked at the total composition of debt in the capital structure, you saw numbers that were higher than the utilities who were the obligors on the power purchase agreements.

That worked; it still works; those contracts are still valid; folks are buying assets to get to those contracts and leveraging it again. The employment of a similar financing mechanism at this sensitive point in time with respect to the infrastructure on power via grids or generation, we believe, would be extremely well received by infrastructure investors.

The contract would mitigate risks that are the unknowns, therefore, the equity capital that will flow against a debt to round out the capital structure will inherently have less risk, and, therefore, should theoretically charge less of a return. That's a way of bringing low-cost resources. Maybe it's not the preferred way, but it certainly is a way of bringing low-cost resources and assets into the marketplace.

So, who might be the determinant of what is needed and how it gets priced? I guess that's the subject of the debate.

We see one alternative as being some objective clearing originator, not necessarily the load-serving entities. It could be whoever is in charge of the reliability of that market. It kind of sits in some taller seat to what we all think exists, and they can see how all these assets are flowing together and the needs of end-use customers are flowing together. And that entity that may be responsible for that reliability could possibly be in charge of gestating the next assets, whether they be transmission or generation, and how that asset should be priced.

That's the conclusion of my prepared remarks.

MR. COLEMAN: Thanks, Frank. We're going to move to some additional comment from Jonathan Baliff of CSFB. Jonathan, welcome.

MR. BALIFF: Thank you very much. I'm Jonathan Baliff, Director of the Global Energy Group at Credit Suisse-First Boston. I'm going to further some of Frank's comments concerning really what I consider the fundamental transformation and change of the bank market in financing generation assets and the overall energy sector and utility sector going forward for the next, I'd say, at least five to ten years.

Over the last three years, there has been a huge upheaval in the bank markets. And when I'm talking about bank markets, I'm talking about the loan market, not investment banks, not the traditional way that corporates and project finance vehicles or generation assets were financed, which was primarily with floating-rate, short, what I would consider three-year term loans to make these plants happen, whether they were in a load pocket or not.

This was the way most of the issuers financed their projects, whether it be the unregulated Calpine, Dynegy, et cetera, or if it was the regulated. They used bank loans.

This has fundamentally changed since the bankruptcy of Enron. Over the last three years, we have seen a shrinking of a bank market which is normally a $900 billion market, to a $600 billion market.

We've seen an increase of a new participant, a new loan provider called the institutional loan market. We also call it the B-Loan market. That has grown from approximately $250 billion to over $400 billion.

There is a fundamental reason this is happening. I want to use an example of the housing market.

Really, when you went to go get a loan for your house, 10 to 15 years ago you went to a bank and they provided you a loan, and they held that loan. But then there came a new market called the collateralized loan market or CDOs, CMOs.

This was able to take the risk inherent in a lot of different loans, pull them together, and allow investors to really just diffuse the risks of these loans. On the equity side of the housing market, what we saw was the RIETs. The RIETs are equity-transformed pools of money that go in and buy either commercial or residential real estate.

This provides, again, a diffused market for equity, so the equity providers, which normally are the developers of housing markets, were able to diffuse their risk. This is why I think you saw that Wall Street Journal article about two weeks ago about why in this economy, even though we have a booming housing market, we have a reduction in economic growth, that many of these developers in housing didn't go bankrupt. Why? They diffused their risk. CSFB's premise is that that's exactly what is happening in the overall bank market.

What we have happening is that the institutional loan market are pools of investors, primarily hedge funds but also insurance companies, providing bonds to many of the same issuers that used to get bank loans. Because the bank market has pulled back, primarily because CSFB, Lehman, and a bunch of us are owning assets right now, which I can tell you is something that we do not want to do -- because of this, we have been able to find pools of investors who will go out and make floating-rate loans on much better terms sometimes than what was available in the project finance market and even in the corporate market for some of our issuers.

Why does an investor want to go to a hedge fund? Again, these are unregulated pools of capital. They normally require much higher return rates than a normal bank.

Why are we seeing these guys entering, and why are issuers accepting this money? Primarily because it is very difficult right now to get a bank loan. They are over 360 more days in duration. Why? Because of the risk capital that is imputed by the regulators on banks is excessive; it's significant, okay?

It makes it very costly and the only way that we can actually make those loans is if we get subsidized with investment banking business or trust business or other ancillary fee-based businesses. That's one way that we'll do it, but other than that, really it comes down to the institutional loan market, which can provide five- to nine-year, floating-rate capital.

This is extremely long capital, and it's provided. It's one of the reasons why you see many of the companies that are in severe distress, such as Reliant, et cetera, get a second lease on life, literally because of these longer-term floating-rate loans that are provided by these institutions.

The other reason that they like to take them or that the issuers like to use this money is that there is less care and feeding. If you're a banker and you make a loan to an institution, you have a yearly bank meeting, you get a steak dinner, you get golf at a nice place.

Guess what? These institutions, they don't care about that. And this is the fundamental transformation the bank wanted. Why don't they care about that? Because they can trade out of their paper. There is liquidity in this marketplace.

A bank that used to make a loan was the lender of last resort. That bank, whether it be Credit Suisse-First

Boston or Citigroup, could not trade that loan. We held it in our own bank as an asset. We had to mark it down if it wasn't performing.

Right now, we have seen an explosion since Enron, of what we call the credit default swap market. This is a market in which I can or CSFB can trade out of their position in companies to manage our risk portfolio.

Just to give you an example, three years ago, before Enron, we had roughly 12 trading parties that Credit Suisse-First Boston would trade with in its credit default swaps, 12 very large parties. There are over 150 counterparties that we have now in trading. It is an extremely liquid market.

So that is one of the other reasons issuers like to go to the institutional markets. They know they don't have to do a lot of care and feeding of these institutions.

Then, finally, when it comes to actually the RMR or financing the RMR market or assets in the load pockets, this is a market that is going to tap the B-loan market significantly. Why? One, longer-term financing, and it can also be cheaper financing than project markets.

Second, if you can mitigate the significant risk associated with RMR -- and that is primarily construction -- the construction risk that most of these investors look at, this market will absolutely flow capital. We're seeing it right now.

The biggest example is the SES or the Project Astoria financing, which has a ten-year contract with ConEd; that will receive financing very similar to what I've been talking about. This concludes my remarks. I'm willing to take questions later on.

MR. COLEMAN: Thanks, Jonathan. To complement this discussion, we've asked Michael Thomas, Sr. Vice President and Corporate Treasurer of Calpine, to give some comments from the perspective of somebody who's out there trying to chase that capital.

MR. THOMAS: Thank you very much. I appreciate the opportunity to be here today and to talk about reliability and must-run load market pricing and those types of issues.

And you're probably ware, Calpine Corporation is the largest independent power producer in the United States. In the mid-1990s, we embarked on a vision to ultimately grow the largest, highly efficient gas-fired plant development program in the United States, if not the world.

We embarked on a vision to ultimately grow up to about 70,000 megawatts in about the mid-1990s, and a lot of the comments that both Frank and Jonathan are giving you and that I'm about to echo here with respect to how Calpine was fortunate enough to have all the stars aligned back about that point in time with respect to deregulated sector that had tremendous influence with the economy as a whole, free-floating capital with respect to lenders willing to commit cheap capital towards the development of merchant assets, as well as the construction risks that you're hearing about from a risk tolerance standpoint.

It was a period of time when infrastructure in this country was primarily 20 to 30 years antiquated. All the stars really were aligning for our company at that point in time with respect to the vision we embarked upon.

At that point in time, though, we were also aware that merchant cashflows were something that was very volatile and very difficult to finance, not only from a lender's standpoint, but certainly from an equity return standpoint.

We looked at things a little bit differently. We looked at things from a diversification standpoint and a willingness to look at things such as portfolio financing that had historically not been done.

Many of the models you had heard about, from an historical standpoint, were very risk-free because of the nature of the off-taking counterparty. Largely you had a PPA with the utility, you had a developer that ultimately went out and got an EPC contract with a strong construction party and basically the risk were pretty well wrapped when that project ultimately came on line and performed from a performance standpoint. It basically just brought in revenues and you didn't have to deal with any of the things that really injected into the market, credit risk and risk management volatility, things that were not part of those prior structures.

As we moved into the merchant finance arena, those risks were not really appreciated, I would say, from what you hear as far as going back to the basics. The basics, basically get to does cashflow have certainty? If not, how risky is cashflow?

In my opinion, I think we entered a marketplace where momentum was largely the driver towards flexibility in capital and maybe decisions that allowed flexibility to be a little bit too far strong. We would argue that that was certainly the case for an asset that was being financed on a stand-alone basis. That asset was a merchant plant standing in the market alone. We felt it was very exposed, it was very exposed, not only in its ability to compete with the broader system, as a whole, but certainly as prices and commodity prices moved, it would certainly have problems as it entered the trough of the cycle.

Our view was, again, to look at more of the portfolio approach and to basically diversify the risk across multiple assets.

In 1998, we raised $1.1 billion dollars for the financing of nine plants across the United States. That was the construction of those plants, and ultimately a mini-perm takeout that gave us the ability to look toward longer-term financing in the capital markets.

Largely, that billion dollar financing went as planned, from Calpine's ability to build the plant and ultimately to get those plants operational. Then we entered into the market with respect to merchant realities.

The merchant realities, to some extent, are what they are, from everything you're hearing today on struggles within merchant spot spreads, the ability to generate sufficient cashflow to either service debt or certainly to have sufficient cashflow for equity returns.

We were able to pull those financings together. We were able to do so with 25 commercial banks at that time. Subsequent to that, we broadened our goals. We raised another $2.5 billion. We raised that, again, on a merchant plant basis where construction risk was included in that. Those assets will ultimately end up in the marketplace, competing on a merchant basis.

We ended up with 45 lenders at that point in time, $2.5 billion of capital. We largely had every project financed by every bank in the world willing to finance us and our merchant risk.

Subsequent to that, as I said, we ultimately performed the buildout and the ability to take most of those assets to ultimately COD and the ability to compete in the merchant world. The reality of what's going on in the world, is exactly what you've heard from Frank and Jonathan with respect to lender sensitivity.

Commercial banks have basically exited that marketplace. We recently refinanced our CCFC $1 billion financing. We did so in the capital markets. There's not a single bank that remains as a participant in that facility.

Largely, the billion dollars of bank capital that we've recycled into the capital markets, admittedly, but bank capital that's available that's not yet been redeployed into the sector. So we have, similarly, our $2.5 billion CCFT-2 facility that's coming to maturity at the end of this calendar year, again, 45 banks with $2.5 billion of capital.

Almost certainly we're going to end up with a large institutional tranche to where we direct or take out that financing, 45 lenders, $2.5 billion of bank capital would be pulled out of Calpine exposure or the merchant risk. In aggregate, that's $3.5 billion of bank capital that was committed as a loan to Calpine Corporation.

We've also seen a similar reduction in our corporate facilities of about $500 million, a reduction in bank participation there. Arguably, $4 billion of bank capital that was committed to Calpine Corporation, is largely not funding our corporation today or as we go forward. I think that's a very important sign with respect to primarily the construction of these assets going forward.

I think construction risk, in my mind, is the biggest risk with respect to incenting a bank or a party to come in to ultimately be willing to finance these assets.

I think what we've seen from Calpine's standpoint is that once we get to an operational state, we've got diversified portfolios of assets. Certainly the capital markets have been the solution for us on being able to refinance. Ratings have not been a material impact on our ability to ultimately find economically-priced capital or the ability to find a marketplace that was interested in having -- you've spoken to a five- to seven-year type of takeout financing.

We've certainly been very successful at executing on that, but, that said, the next incremental merchant asset, I believe, is strongly at risk with respect to where their capital comes from, primarily on the up-front side of the equation, both the development side of the equation, as well as the construction side of the equation. Those are obviously long periods of time. Plants will be developed over somewhere between a three- and five-year period of time. To the extent that that's supposed to fit into someone's planning horizon, there's obviously a lot of capital risk at stake on the up-front side, which is going to be sponsor capital at stake or bank capital, historically, was at stake.

The bank capital no longer being there, there's a big hole in the market to be filled. The term loan B-markets you've heard about certainly have become much more robust and more accessible from Calpine's standpoint.

But, on the other hand, I've not seen that market be willing to look at the construction state of these assets to be willing to take construction risks and ultimately take that asset into a COD state.

I think there's a big challenge on the up-front side as to how you incent parties, ether sponsors or lenders, to be able to look at the construction risk within a market. To the extent that that market is ultimately leading you to a merchant cashflow stream, the examples you've heard about project financing today, are almost certainly related to projects that have contracts.

Calpine itself has been successful in the last year on raising probably about a billion dollars, plus, of project finance capital. Almost all of that capital, though, is related to off-take contracts that we had, that had long-term PPAs, much like the old model you heard about with leveraged allowances, around 80- to 90-percent thresholds.

To that extent, unless you have a contract, again, the challenge of incenting either the sponsors or the lenders to step into that marketplace, I think is extremely difficult in the construction phase. Certainly once an asset becomes commercially operative, I think there are many tools in the marketplace today to be able to finance that on a longer-term take-out. Thank you.

MR. COLEMAN: Thanks, Michael. Do we have a couple of financial questions, or do we want to move on?

MR. PERLMAN: I have a quick question: I heard both Frank and Jonathan talk, and, I guess, Mike, a little bit, about cashflow certainty with respect to the financing of new infrastructure projects. Could you elaborate a little more on that?

Are there different ways to get the cashflow certainty? I heard Frank talk about a contract or something that would be an equivalent of a contract from a regulatory perspective. I guess we have some influence over how to set some pricing structures up, but what would the financial markets see as cashflow certainty-type structures that would be financeable?

MR. THOMAS: In my mind, RMR itself is not really cashflow certainty; it's more what I would just use as a generic example of a check-engine light. If there is something wrong, there is a signal within in this marketplace that says that, economically, someone should be coming in to step into that role.

RMR itself is a short-term subsidy or something that does not have certainty from a continuing standpoint or a renewal standpoint. It's not a cashflow stream that I think many lenders become comfortable with. To the extent that is a marker, certainly it's telling you something about the marketplace as whole.

You do get to additional diligence levels, but I don't believe that the RMR component itself is sufficient to incent either a sponsor, or, ultimately a lender to be willing to finance that risk at the end of the day.

There are other means than just contracts to ultimately finance these things, but a lot of them come down to more derivative types of products that are very expensive to ultimately provide you largely the same answer. Could you conceivably come up with a floor on your merchant spark spreads that ultimately buy an insurance type of product that gives you the ability to get lender certainty, that would be able to serve as debt? That's basically some form of a quit obligation or some form of contract-like obligation, that if prices fall below a certain level, certainly those structures are out there.

But those structures are extremely expensive.

The credit default derivatives you've been hearing about are products that have existed, too, but they are very, very expensive for parties ourselves or lenders, I would say, to ultimately purchase, to be able to protect the risks.

So, outside of a contract, I'm struggling with respect to what's the Band-Aid in between. I'm not saying a contract is ultimately a ten- to 20-year contract that historically existed, but certainly, a one-year uncertain renewable type of incentive is not sufficient to get you into a longer-term comfort level that the capital you're deploying, again, three to five years up front, ultimately has viability in the longer term, which is, again, the 40-year-plus type asset.

Until you figure out a way to bridge those two together, I'm not sure that RMR, in isolation, is anything more than a signal that the marketplace has a need.

MR. NEPOLITANO: I think construction of a marketplace, not physical, but the financial construction of a marketplace is equally important. The contract assumes a lot of things. It assumes that there is a mechanic to measure something and there's a freezing of that measure in terms of a price point.

The mechanic you need to get to measurement is equally important as freezing it at a level that's economic to the participants. It's not clear that in some of these markets, the mechanic is transparent, and there is some over-the-top activity and new type activity that is risk in those markets as they develop either transmission or generation.

As capital thinks about looking at that precipice of risk, that lack of transparency with respect to the measurement of the metrics, is equally a problem as freezing those metrics at an equitable level.

MR. BALIFF: Just to say something different that deals with the terms of the contract itself, I agree with my comrades here that from the standpoint of how you mitigate risk, kind of water seeking its easiest source, is a contract with a firm capacity payment. The market is very willing to take operational risk. It's even willing to take construction risk. One thing it can't do, it can't keep layering on these risks and say it's a financeable construction with market, operational, and regulatory risks. It's not going to happen.

So if you do have a contract, the question is, how does that contract need to be, if you have these types of BGS type contracts of one to three years, okay? And you have significant mitigation of your construction risk, either through some type of insurance, what we call a wrap, a guarantee, or if some corporate will guarantee it of an investment nature, then I think that is perhaps financeable.

There is going to be a significant amount of structure around it, but it is financeable. If you get into the five- to ten-year contract range, that's where the gray area sits, and it really is going to be load-pocket-specific. It's going to be construction-specific.

I would say that for the issuers at CSFB, Credit Suisse-First Boston, is dealing with, the construction is, by far, the more significant risk than even the market risk right now for specifically the RMR. Why? Most of these projects are in urban areas, and the nature of the pricing has, in general, been double what the original projection said.

So, for example, SES is counting on double what it originally bought ten years. Many of the projects on the gas pipeline going into New York City, those have all been doubled -- the price -- just because of the nature of developing infrastructure projects in urban areas, so I'd say, if you can get the five-year contract, mitigate the construction risks, then you'll see the capital flow.

MR. COLEMAN: We're going to have Frank, Jonathan, and Michael, continue on with the second panel, so, to the extent we need to follow up on some questions there and get some more observations, we will do that.

I'd like to move into the second panel to keep things moving here. Our first speaker on the second panel actually really needs no introduction. Bill Hogan is from Harvard University with a long description that I condensed to purveyor of wisdom and economic justice.

(Laughter.)

MR. COLEMAN: With that introduction, Dr. Hogan?

MR. HOGAN: Thank you, I think.

(Laughter.)

MR. HOGAN: It's a privilege to be invited to participate. I remind you that I don't speak on behalf of anybody else; the comments I'm providing are just my own. I have prepared some remarks, which I have submitted for the record, but in the interest of time, let me try to just summarize, so that we can get into the discussion later.

When I looked at the Order that came out, I was a little taken aback by the several pages of outline questions. I had first thought about trying to answer them, and after awhile, I realized that for most of the questions, the answer was "maybe," because, as I refer back to the Chairman's introduction, it's very fact-specific.

So I think you have to go at the particulars to get back down into that level of detail, which maybe we can do later. So I thought I'd step back and just make a few observations about more general issues from a market power mitigation perspective to either reveal my own conclusions or biases in this matter, and then I hope that will provide the foundation for later discussion.

So I put together my top ten list of things here that I would want as take-aways, and the first is that, as I think is generally recognized, but just to say it, in balancing imperfect markets and imperfect regulation, we should lean towards markets and restructuring.

You want to avoid trying to go too far to overregulate things to make it the perfect competitive case, because I don't think we know how to do it. We probably would do more harm than good.

Number two, market power models are useful for stimulating thinking, but I don't believe the numbers just yet. I spent a lot of time building and using formal models of many things, including market power. I think it's a very interesting topic, and I've become convinced, looking at it, that it's really complicated.

The shorthand that we use for this, like concentration indexes, or, more recently, the concept of pivotal suppliers, or any of the various game theoretic models and all those kind of things, I think are helpful in stimulating thinking, but I wouldn't use the numbers very much, because I just don't think it's possible to get past the simplifications.

So I think the place so far that the best focus is for diagnostics, is direct analysis of withholding by individual generators and to look at the particulars and see what you can find. That is done, for example, by David Patton, Joe Bowring, and that's the great thing, I think, to focus on.

Number 3, scarcity pricing is good, withholding is bad. This is what makes all of this market power mitigation hard, because you just can't look at high prices and conclude that people are exercising market power. It might be nothing at all like that. It might just be scarcity pricing, and that's good, so you want to support that and encourage it. It's the withholding you have to focus on, and that's critical.

Number 4, electricity markets may make control in real-time generation, transmission, or load in exercising market power, because of the particular physical nature of electricity and the way these clearing markets work, at least in organized markets.

You can't use derivatives and forward contracts to exercise market power, if you can't do something in the physical market that actually occurs in real time, so that's the place to focus and to look at what actually happens in real time.

The other parts are interesting because they contain incentives, but they don't actually create market power, but market power exists in real time.

Number 5, improvements in market design under competitive conditions also help address market power problems. This is less of a surprising idea nowadays because we've had a lot of experience. But initially, there was an attempt in various parts of the country to modify the market design in order to get rid of the market power problem by creating a big zone or something like that.

We now know that that is actually counterproductive. I think there's actually no tradeoff. When you're considering market design issues, you can assume competition, a competitive market, design the market accordingly, and you won't cost yourself anything in terms of market power. You probably help.

You won't solve the market power problem, but you just don't make it worse and you don't have to worry about that.

Number 6, monopsony, is a problem, as well as monopoly. Looking for situations where people are taking actions to depress prices below competitive levels is just as much a problem, and we should worry about that.

Number 7, market power mitigation, should default to the competitive outcome when market power is not present or not exercised. Bid caps are much better than price caps, because bid caps don't constrain competitive suppliers who would bid under the bid cap. That's the kind of thinking that I think we should continue.

Number 8, entry is crucial in long-term market mitigation of market power. It's because of the lure of the extra profits that people enter the marketplace to make -- this may come up later in the conversation. When you go through the analysis, you could come to the conclusion that for entry and for new generation, you could take the view that you don't have to worry about it, and you don't mitigate new generation that's not owned by the same companies; you just let them do what they will, and that provides the right kind of incentives, as long as the entry barriers are level.

Number 9: The discipline of markets requires the possibility of losing money and the exit of money losing generation. It doesn't mean you don't need a market power analysis for that, but exit through asset sales is quite different than exit through closure, for example, and we can talk about that later, but I don't think we should be excessively concerned about people who are losing money.

Then, finally, there is Number 10, market power mitigation policy needs its own exit strategy, so looking at ways to design the policy and then it sort of fades away over time. That is consistent, for example, with exempting new generation and new investment from market power mitigation, going forward.

And there are other things that we can consider in that line. So, in conclusion, the emphasis should be on good market design, expansion of market participation, reducing restrictions at seams, encouraging entry and so on.

Local market power will continue to be necessary, but it should not drive other policies at the risk of defeating the basic purpose of using the discipline of the market, rather than the discipline of rules. Thank you.

MR. COLEMAN: Thanks, Bill. We're going to continue with all the speakers, and end up with a Q&A session afterwards, although I know the any speaker would have a number of questions generated from his or her comments.

Next we have Michael Schnitzer, cofounder and Director of NorthBridge Group, appearing today on behalf of Exelon Corporation. Welcome, Michael.

MR. SCHNITZER: I appreciate the opportunity to be here this morning and to speak after Bill Hogan. But I'm going to try and describe some of the thoughts that Exelon has. I have the perspective, both of a transmission distribution owner with RMR issues in your service territory, and also as a generation owner. The perspective that they have developed, I think, is a balanced one, which, with any luck, will be of benefit to the Commission as we go forward.

I have a presentation here that I'm not going to use, which some of you have a copy of. But I'm going to refer to certain pages of it, but it won't be fatal if not everyone has a copy of it. I'm sure we can get other copies made available.

Let me start with the definition of what reliability, must-run is, as I'm going to be describing it. Basically, as Bill described it, it's a physical generating asset that is needed for reliable grid operation, whether it's in merit or not. It just needs to be operated for whatever set of security reasons or another, and the transmission fix is either infeasible in the timeframe we got to real time, or it's not economic, relative to having the generator there, and that's something I think we should also keep in mind. Not all RMR solutions are economic to fix on the transmission side. That's my definition.

The comment was made at the outset about the fact that this is fact-specific. I think that's the case.

The problem is that RMR situations come in many varieties. There are units that are RMR that most of the time, they're in the market and economic to run, whether they are RMR or not, and only occasionally do they have this RMR characteristic. Coal plants, for instance, they are in the money most of the hours, and there are units that are not. Most of the time they run, they're RMR.

There are units whose RMR status is predictable under normal operating conditions, and there are units where that's not the case, where it's only in the hottest of summers or under a previous contingency that they become RMR, and those are very different.

And there are circumstances where the existing stock of generation is adequate to meet the RMR of reliability needs, and there are circumstances where load growth says that they are not, and you're going to need some new entry of some sort or another. That's the problem here, is that you have so many of these different fact-specific circumstances from which RMR situations arise.

For those of you who have the package, I'm just going to spend a minute on page 3. The consequence of all of those different fact situations is that one size does not fit all.

A bid cap, for instance, which is used in some circumstances, won't work for some non-market units whose hours are not predictable and otherwise don't have any in-the-money hours, no matter how high you set the cap, because of infinite cap and zero hours don't generate a lot of revenue.

Even where the caps are workable, a single formula may not be workable. You have one unit which, five hours a year, it's RMR and 8,000 hours a year, it's generating energy profits, and variable cost plus ten percent may be great for that unit.

You have another unit that only runs 100 hours a year. They are all RMR units, and variable cost plus ten percent is not going to cover the O&M and the property taxes, you know. for that kind of operation. If you set bid caps and replacement costs, that may encourage entry when you need it, but if you don't need the entry, it may result in what some people would consider to be overpayments, you know, and monopoly rents to generators. That's the problem we have.

Let me just spend a few minutes here on page 4, on how we think about that, and map that into some different circumstances and some different potential solutions. I'm going to start with circumstances where current supply of generation and transmission is adequate, which is to say we don't need more generation for voltage or we don't need a new transmission fix.

We can meet reliability criteria, as long as we have the RMR controls that we need. If we have units, first of all, that run predominantly in merit, and for those, the bid cap is variable cost plus ten percent, I assume the market monitors here will speak to, may well be a fine solution.

But then we have units that run primarily for RMR reasons and they're not in the market. They are not low-priced coal units or whatever. And then we have a split. Some of those are fairly predictable.

You know the number of hours they're going to run within certain bounds that are reasonably predictable, and there are some where you just don't know. It's not predictable at all.

For the first of those, which is Category II in the picture, for those of you who have it, bid caps can again work, but it might not be variable cost plus ten percent; it might have to be a higher bid cap.

For the third category, bid caps may not work at all. You may need some kind of demand charge or demand payment, because if someone doesn't know if they're going to run one hour or 100 hours, it's pretty hard to set a bid cap that will make everybody happy.

Then, finally, the complication, is if that wasn't bad enough, is that you have some units that are facing major capital additions, extraordinary kinds of things where every now and again, it's a really old unit and, son of a gun, I've got to rebuild the turbine and it's going to cost me a bunch of money, or I've got to rewind the generator or do something like that, or I've gotten an environmental requirement that's going to require me to spend a lot of money. And the one-year bid cap or one-year demand charge contract may not be adequate to make me incented to make that investment.

So in those circumstances, you might need to have the opportunity for multi-year, longer than one year arrangements of demand charges or bid caps or both.

Finally, we have what we refer to as the scarcity situation, which is, it's great for the units that you've got, but I need some additional units or I need a transmission fix or I need a generation fix. And there, that's a more complicated story that I'm not sure fits in the timeline and the time available for my opening remarks, but we can come back to that one.

So what that all boils down to, I think, is on page 5. RTOs need an RMR menu, basically to deal with the flexibility and to deal with all of these circumstances. You need the ability to have a formula bid cap for the in-market units, a negotiated, higher-level bid cap for those Category II, predictable RMR annual contracts with demand payments for those units where the hours of operation are not at all predictable, multi-year contracts to deal with circumstances where new investment is needed to sustain that plant and avoid retirement, and then some things to deal with new-entry pricing, either transmission or generation. We'll wait for your questions later. Thank you very much.

MR. COLEMAN: Next we have Roy Shanker who has some comments who is a consultant for numerous generators and financial market participants.

Welcome, Roy.

MR. SHANKER: Thank you. I thank Staff and the Commission.

As mentioned I work for generators, financial participants in the market, also for some transmission owners and LSEs. And, as usual, these are my own comments.

Following, I'm looking at it from the Staff's perspective. You see me to the left of Bill and to the right of Joe and David. That's probably reasonable.

(Laughter.)

MR. SHANKER: At least most of the time and I think like BIll I want to take a higher view of this because I think we'll get into a lot of arguments, as Mike pointed out, about the specifics.

And Bill will go up and back in detail with that as sort of a start. It's worth it to start by putting everything in perspective with it to start.

In general we look as these kinds of RMR local market power issues. The focus is always on fixing the immediate problem as perceived -- it's sort of the "squeaky wheel function." Then we see them, we do the patch, and then we tend to forget very often in the general context the objectives of what we're trying to do with the market design overall.

Typically that's a huge mistake and I think what I thought we were here to do is to try to establish a competitive market structure to support efficiency and send market related price signals to both generation and load and, in turn, try to spur new entry, either by generation or by load management or load control in meeting the market demands for power.

Everything we do ought to come back to the test of reasonableness against that objective as opposed to "did I fix today's market power issue?" When we don't do that we're on the road to making a lot of mistakes.

In that context, the first question we ought to ask ourselves when considering a potential market power or exercise of market power in a small area is whether or not we're seeing a permanent market failure or whether we're seeing some sort of a transitory point or hopefully a transitory point on a path to a workable competitive solution.

I think the way we approach mitigation of the local market power and local pricing can and may be different, depending on the answer to that question.

In the abstract you sort of want to do the same things but I think when you start to make the policy calls, where you start to move outside the market response, to actually desigining fixes, where you see a situation where you say "Hah, this is not going to be solvable ever," we have a basic market failure -- you're going to do things differently than, you know what? We see things today.

We have potential for the exercise of local market power but underneath all this we have workable competition down the road but the reality is it's expensive and we're going to have to pay something to fix the problem and we're going to have to show people the prices that are associated with that.

I think, if you make that distinction right up front, you're going to follow a different path. If we find that there is a transitory path to workable competition, we want to emphasize compensation and full compensatory rates -- I'm sorry. If we think there's not going to be workable competition, then we have a market flaw.

I think probably the objective switches to something that is more focused on full compensation and efficiency may lag. I'd like to match them both but what you really have to worry about is getting to an efficient solution as quickly as possible.

Looking at only part of the problem in this context and getting the seemingly right price for new entrances is probably a mistake if that is all you look at because what we're going to wind up doing is having a problem with theincumbents and we're going to always have a recurrent problem of "we can't fix that" because new entry will not come on its own.

Also, if we put together patchwork solutions in the market failure case I think we're also going to wind up with solutions that tend to have a lot of properties that look like the exercise of monpsony power.

We can talk a little bit about that later.

Alternatively, if we think there's a structural -- no structural bar to entry or it's a low entry barrier, then the focus would be on understanding why the current situation isn't resulting in workable competition. Why is there the potential for the exercise of market power that exists now and do just what Bill was saying, develop pricing and mitigation strategies with the intent of moving towards a workably competitive solution?

You look at this as a transition point, not as an end-point. It doesn't mean no mitigation of market power exists, but it means mitigation coupled with as accurate a pricing as possible to allow market recovery of cost by participants both generation and transmission.

The basic pricing elements here have to be targeted on short run pricing signals that reflect locational energy scarcity and locational installed capacity, if necessary.

The main elements here, as usual, are getting the prices right first, then worrying about the mitigation.

If we have the right price incentives for everybody's behavior, the mitigation almost becomes obvious.

In fact, the distinctions, if you work through the details between some of the arguments that exist between PJM and New York in mitigation strategies almost disappear.

If we start to see scarcity pricing like demand reserve curves, locational ICAP, all of the typical pick-up everything that should be on the table for the correct short run price signals -- when you do that it becomes almost obvious how to mitigate because if you do things kind of cost plus mitigation or you do things like impacting fresh hold mitigation in the right scarcity pricing scenario you're going to get the same answer, there's not going to be a differenc.

A quick example, and I probably won't get to do much of it, given where the time is going, is to put those principles to work in the context of something that's actually happening and I think probably what you'll hear more about tomorrow is the PMJ example and I think what you need to look at in a situation that comes about -- they're assuming that there is a workably competitive solution -- is to go back to the basic principles and say "here is a situation in PJM that's predicated on physical scarcity."

At least the auction proposal that's coming up and the concern that either retirement or lack of new entry will lead to an OMR reliability issue because incumbancy will not be earning sufficient revenues to stay in the market and, if you go back to the first principles that we're taling about here, and say "we're trying to send the right price signals," then you scratch your head and say "we're trying to send the right price signals" but somebody who is absolutely needed for reliability isn't earning sufficient returns to stay in the market.

What yu ought to do in a situation like that is say, "Hmm, I think there's workable competition down the road. I think there's new entry." It may be expensive in that situation but how is it that a unit can be vital and at the same time not get any capacity revenues, which would be the case in today's world and, two, possibly not getting sufficient operating margins to stay in the market under cost plus ten pricing.

The answer ought to come back reasonably quickly. The first thing we ought to do where we think we have a transition to workable competition is to get those prices right. That means to go for scarcity pricing and to look for locational reserves -- one option, as Bill was talking about, locational installed capacity payments or other pricing remedies -- and see if they resolve the problem as a transitional point towards a workable competitive solution, as opposed to immeiately going to solutions on RMR type contracts that are probably more consistent than a permanent market failure.

MR. COLEMAN: I know we'll be getting into that a lot tomorrow and I think the conversation and the Q&A will follow up on that.

Next we have David Patton, President of Potomac Economics, and a market advisor to a number of organized markets here in the U.S.

MR. PATTON: I appreciate the opportunity to speak today. Like the others, these comments only represent my own views, although I'm optimistic that my clients might agree with some of them.

(Laughter.)

MR. PATTON: And probably not -- I'm going to try to move quickly. My goal is going to be to try to lay out a framework for thinking about some of these issues because I think sometimes we get confused and try to identify what the real objectives are.

What we're trying to balance is two objectives. The first is establishing efficient economic signals in load pockets.

The second is mitigating excessive market power that often exists in a load pocket.

Most of my comments are going to be focused on the first area. I probably won't have time to say much about the second, although suffice it to say that I agree with Bill, that resource-specific offer caps, I think, are clearly the best solution because they allow the market to continue to operate and are the least disruptive.

But we can talk about that more in the follow up discussion so I'm going to focus on the economic signal, which I think is really the key.

The first thing I would say is it's critical to recognize that new investment is not always necessary int he load pocket. We often hear things or talk and make statements such as "we need to make sure that signals are sent that we need investment in a load pocket."

That's not actually true. What we want is an efficient economic signal so that when capacity is needed in the load pocket, we're sending that signal but, when there's a surplus in the pocket, we're not sending that signal.

Even when there's a surplus you can have significant market power problems. You can have a surplus of capacity in the load pocket but it's all earned by one player.

Secondly, I would say, moving down into the economic signals, where does the source of value come for resources in load pockets? It comes from two primary things. One is the ability to relieve transmission constraints, which should be reflected in the locational marginal prices in an LMP market.

But second is that they provide capacity value in the load pocket to maintain reliability.

I would say all but one of the centralized markets have no market mechanism to account for this value. What happens is we get into a situation where the RTO says "I need the capacity." The owner says "It's not economic to keep it in operation" so you default to an RMR contract.

What that's a symptom of is "is the fact that the market isn't complete and doesn't reflect that value?" The exception I'm talking about is New York City where there's a locational capacity requirement so there's a means of pricing it.

What I'm going to try to lay out for you is five alternative sources to price that second source of value for resources or compensating generators in load pockets. Number one is location-specific operating reserve requirements. Nearly all these markets that have recognizable load pockets have a capacity requirement that they use on a daily basis to commit generation.

Usually they call that a "local reliability requirement." What that means is that a non-market requirement that the operators have to meet but there's no market equivalent of it so there's no pricing of that constraint in the market.

On establishing location-specific operating reserve requirements you can do effective shortage pricing in that area so that, when you can't meet that requirement, you reflect the economic value of those reserves in the energy price in that area that's being proposed on a broader basis in New York right now.

The drawback is that, if there's been a history of insufficient investment in transmission and generation, putting this in place can create an overwhelming signal that would be difficult to implement in one step.

So that's the primary drawback.

The second alternative is the locational capacity market, which you can think of as a proxy for those short term capacity requirements.

The longer term capacity requirement that exists in New York City today -- it's a signal that's not likely to be nearly as volatile and can be phased in in an market where none of these requirements exist.

The third alternative would be an RTO auction for new capacity in the load pockets. An example of that is what PJM is proposing. It's very similar to the locational capacity requirement except that it's a more discrete process and it establishes a longer term obligation with the new supplier.

The important thing is that the clearing price from that process needs to be paid to the existing suppliers in the pocket in order to set a market clearing price for the capacity in that area.

Number four, if you don't do the first three and we don't do the first three -- with one exception, is loosened market power mitigation and an example of that is "push" provisions in New England -- when we get into a debate about how high we should set offer caps when we mitigate so that we preserve signals, what we're really debating is this fourth alternative and what we've implicitly done is decide we're not going to do the first three, which I thnik is a mistake, because if you do the first three so that you're pricing on a market basis, the value of capacity in the load pocket -- then it substantially reduces the concern that your mitigation is too aggressive and is going to prevent price signals in the load pocket from being efficient.

The problem with this approach is it's less reliable than the prior approaches because it relies on the exercise of market power to generate the signals so you can have a situation where you have concentrated supply in a load pocket which leads to excessive signals when there's a surplus or what we've seen in some of the "push" results is that you can have load pockets where the supply is sufficiently deconcentrated that you need investment but nobody has enough market power to generate the signal even when you loosen the mitigation.

Lastly, the worst alternative is unit-specific RMR contracts, but the default of everything else fails -- is my least favorite because it sets the least transparent signal. It doesn't represent a market clearing price in any sense and I think, as some of the finance community commented, it's least likely to generate new investment because of relativelly short term commitments for the generation in that pocket.

I'd be happy to talk about my views on mitigating local market power in the discussin phase.

MR. COLEMAN: Thank you, David.

Next we have Joe Bowring, PJM market monitor. Welcome, Joe.

MR. BOWRING: Thanks for the opportunity to be here to day.

I agree with the general overall comments of David and Bill who preceeded me. Let me try to add something to the discussino.

First of all, the context for all this is broadly competitive wholesale markets. Within that context, local market power situations are really an aberation as you know from the data we've made public about PJM in particular, even though cost capping gets a lot of attention that does not really occur very frequently.

We don't really have many load pockets where it occurs. Nonetheless, it has to be addressed. The goal is to ensure competitive outcomes in the presence of local market power and, ultimately, as a number of our speakers today have suggested, to reduce local market power, and finally, the need for mitigation.

It's also useful to bear in mind that the impacts of local market power can be quite significant.

In the recent Delmarva proceeding before the Commission there was some discussion whether or not there was market power.

Yell at me. I'm not supposed to talk about this, David -- there was some argument that market power existed. There was significant congestion.

Nonetheless I don't believe there was local market power exercized. If there had been, the levels of congestion could have been from five to ten times higher than they were in fact.

Local market power is, simply put, the ability of a generation owner to raise the price in an area above the competitive level.

The competitive level is well-defined. We may quibble about whether it's the right mitigation level but the competitive level is the short run marginal cost.

This is not a hypothetical or theoretical point. This is the way that the generators actually offer their power in the broader PJM market.

In many load pockets we have more diversity of ownership and that's exactly where we'd expect to see it. Local market power was created, as others have suggested, as you know, as a result of transmission constraints.

Those transmission constraints can be either temporary or longer term and they effectively create monopoly power at the margin for one or more owners of generation in the area defined by the transmission constraint.

So far it's worth noting, as others have, that there are two broad categories of mitigation we have to think about. One is in situations where there is scarcity and the other is in situations where there is not scarcity.

In situations where there is not scarcity, clearly the approach -- I believe the approach we have taken at PJM makes a lot of sense -- and that is, simply, the higher of the market price or cost plus 10 percent.

When that's criticized, frequently the result and potential impacts on revenues are discussed but, in actual fact, when you look at the details, the net revenues of those units that are cost capped do not vary significantly, contrary to what one might expect -- do not vary significantly by the percent of hours cost-capped.

Par of the reason -- or really, the only reason -- that net revenue has been an issue for units in PJM including those in load pockets has not been local market power mitigation but has been broad market conditions.

As one understands that prices in the broader energy markets, as well as capacity markets have been depressed compared to historical levels, and also compressed compared to expectations, wherein a low period of pricing in everyone's net revenues, are down -- cost-capped units are not disproportinately effected.

In fact, it's a broader market issue and it's very important to keep that in mind when designing local market power mitigation in order not to overreact to the broader market results.

The second broad category, of course, is when scarcity exists, local market power can and does exist for that scarcity. In fact, in general in PJM, load pockets do not have scarcity. Generally there's more than enough generation in the load pocket to serve the load and that of transmission import capability.

So it's not a question of scarcity. In that case, scarcity pricing clearly of any kind doesn't make sense.

Nonetheless, as we pointed out repeatedly, and everyone understands that situations of scarcity do have to be addressed, David and Bill and others talked about ways to do that. "Scarcity" again I'm defining as 'the inability of existing generation to meet load reliability in a load pocket."

It's an engineering definition but I think that it also works for economic purposes as well here. We need to create market based incentives to resolve scarcity issues and what we propose and will talk about in detail tomorrow is an auction.

But the intent is to have, as I said, a market based mechanism, not an administrative mechanism.

Unfortunately scarcity pricing, while it sounds like a market based mechanism in a load pocket with one or two generators ultimately boils down to an administrative mechanism -- someone has to decide what that price is going to be. It doesn't fall onto the market particularly when you have no demand side.

While I agree, I think, with all the speakers that the market based mechanisms are appropriate, we have to be very careful to get past what appears to be superficially a market based mechanism to ensure that we literally are having a market based mechanism.

An essential component of the option we proposed is that all forms of solutions to load pockets get to compete against one another heads up. That is, transmission generation as well as DSM. All three of those are ways of addressing load pockets. All three should be considered and should be considered in a market context so that the least cost alternative as defined by the market gets to solve the problem.

Our MR contracts might well be a last resort in situations as have been defined where local market power is a long term systemic issue and there's never likely to be a market solution and there's never likely to be a transmission solution and there's really no alternative.

But it clearly is a last and, in my view, poor solution. Thank you.

MR. COLEMAN: Thanks, Joe.

Next we have Roy Thilly, Chief Executive Officer of Wisconsin Public Power, Inc.

Welcome, Roy.

MR. THILLY: I'm going to swim a little bit upstream a little bit this morning and suggest that LMP, with significant or high mitigation ceilings is not the right approach to what ought to be the objective, which is to get the infrastructure in place and constructed so all customers will benefit from competitive wholesale markets.

I come from the perspective of being in one of the worst load pockets in the country. We are the ones who would pay the scarcity price if the system works and will pay it for an extended period of time because the fixes are not quick.

If in fact the incentives don't work as intended, we'll continue to pay it while others will go back to the drawing boards and look at an interesting problem of what to do next.

I would urge the Commission to be careful to recognize that there will be gaming, particularly of complex mitigation arrangements. The theory is elegant but the facts on the ground are messy.

I think there are two key questions that were asked. One is, is there a single policy that fits for all markets? My answer to that is, "no there's not."

THe facts are different. The economic drivers are very different. An obligation to serve states in retail access environments and the entry barriers are very different in the different places.

If you don't take account of that in the design the design will fail.

How important is infrastructure to solving theload pocket problem? Transmission infrastructure is essential for solving the problem. If you get a robust transmission system, market design is easy and gaming is very hard. That should be the objective. The objective should be generation to generation competition. that's what will benefit customres.

The idea of having transmission compete against generation is I think a false solution that will result in a significant dampening of generation competition.

Transmission is very, very hard to build and needs to be addressed on its own merits. I have a concern that some think there is a legitimate interest in congestion that needs to be protected. FTR values, the value of constructing a generation load pocket -- there maybe an interest but it's not an interest that should be protected or fostered by market design.

I fear that high mitigation ceilings will create a segment, probably a powerful segment with an interest in maintaining congestion. It will certainly dictate bidding strategies over a mix of generation in annd outside of the load pocket to maximize profit but not necessarily to stimulate entry.

And I fear that it will create a whole new class of environmentalists concerned about the biodiversity of new transmission right of way.

You have to look at who can build -- one of the big problems we have is that the RTOs theoretically have the ability to compel construction but I think that's extremely difficult. I haven't seen it done in a large owner. Benefitting from congestion can create many, many roadblocks in the state process to getting transmission built and built promptly.

What are the "must-haves?" I think you have to look at "must run" policy in light of the broader market design. I'd say the "must-haves" are, one, a system that focuses specifically on getting transmission constructed for load pockets. There are a number of steps that can be taken there that I can elaborate on.

Resource adequacy requirements are essential. Starting up with a market without resource adequacy and depending upon spot energy prices to cover fixed costs is a disaster from the load pocket perspective.

I think we heard it also is not finance-able. We need certainty, transparency and the ability to cover fixed costs, and a capacity market must run loosened arrangements and so is very problematic from a load pocket perspective.

We need the capacity market. Then we should price "must runs" at marginal plus a reasonable profit, 10 percent profit -- unless you have true scarcity. The problem is differentiating between scarcity and withholding.

Most of the schemes don't really try to do that. They just set a high ceiling and mitigate without determining. I would say true scarcity exists if you have to dip into operating reserves and you can't replenish them within the short period of time you're required to do so by the reliability rules.

Also, you have to have an accurate assessment of the barriers to entry. They will be different in different places and the barriers to entry where I live are very high.

We have obligations to serve the State. We do not have any IPPs that control their own generation. It's all under contract to the big players and there are no IPPs that are going to build on speculation of energy prices.

That gets to the point that you need consistency with the retail model that you're operating in because the retail model is going to provide a lot of the drivers that influence behavior and if you have an inconsistent wholesale model on top of it, you're asking for trouble.

Finally, just a comment on the incentives -- as I look at it where I live, scarcity pricing incentives take at least five years to solve the infrastructure problem.

In the mean time, what we see happening is industry shifting production elsewhere out of state -- paper companies shutting down paper machines and maybe won't have to build when they get down to the building cycle.

But that's not the kind of incentive that makes sense from our State's point of view.

Thank you.

MR. COLEMAN: Thank you, Roy.

Our last speaker on this morning's panel is Abram Klein from Edison Mission Marketing and Trade.

Welcome, Abram.

MR. KLEIN: Thank you very much. I'm very glad to be here.

I am director of Northeast Trading for Edison Mission Marketing and, trading as a market participant, I see how some of these market design issues actually play out in terms of market performance on a day to day basis.

I'm also an economist that has worked on local market power issues currently and in a previous life.

What I want to do is focus my comments on two main areas, the first is to look at the local market power problem in a broader overall market design context and look at market performance in that context.

If you have a generator that's inside a load pocket that's needed for reliability and it's not making enough money, why is that?

Well, it could be that the prices are not high enough inside the load pocket.

It also could be that the prices are not at competitive levels in the market more broadly. I think you have to do that assessment in order to determine what the proper policy prescription is.

I think that sort of approach, looking at the broader market design, is consistent with the standard market design.

The second concern which I will try to address later if there's time is what I'd refer to as "mitigation creep" and that is the Commission is given sort of a broad based authority to the market monitoring unit to address it but it's not very narrowly defined and it can be used in ways that I think with not necessarily the intention but it might be appropriate to prescribe a little bit more what should occur.

In terms of the broader policy context, lets look at market performance in Northeast ISOs. How are these markets doing?

Well, if we look at the period from 2000 to 2002, each of the Northeast ISOs had very tight reserve margins on an annual basis. During 2001 and 2002, each of the Northeast ISOs had multiple days of real scarcity and very many high demand days, particularly in 2002.

One would think that spot energy prices in a workably competitive market in that environment should have actually been above the cost of entry and perhaps significantly above the cost of entry -- at least not just at the cost of entry.

The reason for that is basically two reasons. The first is that we know the entrant is going to expect the commodity market to be somewhat cyclical and go through a "bust" cycle so the prices need to be higher during the period when demand is very tight -- or the capacity margin is tight and the demand is extreme, to make up for those later, lower periods.

If you don't have prices that are at entry cost when demand is extreme and the capacity margin is tight, that certainly bodes poorly for the overall market structure. That says that the market structure is flawed and part of the result would be the loss of investor confidence in the energy supply business.

So in looking at how the markets actually performed -- I provided in my prepared comments some tables that look at it, but certainly my analysis of it is no different from the ones provided by each of the ISOs in their states in the market reports looking at 2001 - 2002.

That is, the actual market prices were significantly below the cost of entry even when entry was needed during those periods.

What I'd like to say is that the response to the current market structure flaw has been different between the different ISOs. In New York we have had a set of initiatives and reforms aimed at addressing scarcity pricing and addressing market flaws in the reserve adequacy market.

The installed reserve markets -- those have taken place in 2003 and I think those are scarcity pricing and energy demand curve end reserves. There's also an interregional effort to look at a longer term market for reserve adequacy as well in the Northeast. We'll see how that goes.

But those are all potential solutions to the broader market problem. In PJM we still have the same market structure -- essentially that we had during 2000 and 2002 so, if we look at the "must run" problem in that specific context, you really need to fix the broader market first there and deal with some of these issues first before just addressing the load pocket problem or scarcity problems.

If you only look at the load pockets essentially what you have is a situation where you're price discriminating so that capacity inside the load pocket actually gets paid a higher price even though what you really need is higher prices in the market more broadly.

Let me just briefly address the other issue, which is "mitigation creep."

My concern here is that some of the authorizations to do cost capping, say in PJM, were developed in 1997 before we had any experience with the market. Those authorizations say that any time that there is a transmission constraint anywhere in the pool, there can be cost capping unless it's one of the three major interfaces.

I think that was appropriate at the time when we didn't have any experience with the market. But a lot has changed since 1997 and I think that we ought to be looking at revisiting where that authority lies.

One of our concerns is the market monitoring unit in PJM would like to use the authorization to mitigate local market power to, under certain conditions, declare the whole Northern Illinois area as a load pocket.

Once Com Ed is integrated int PJM under certain circumstances, Northern Illinois is a bigger area than New England. There could be a situation where you have no transmission constraints within Northern Illinois or into Northern Illinois from the surrounding regions.

Yet that area would be declared a load pocket simply because there was a contractual constraint on the contract path from PJM into Northern Illinois -- so I think that it would be appropriate to look back basically at the overall authorization to do mitigation in some of these circumstances and fine focus on where the load pockets are and I think we know where they are generally in PJM and just narrowly address local market power mitigation to areas where there really are local market power problems.

Thank you.

MR. COLEMAN: Thank you.

I know I had promised folks at the outset that my time management would be good and we'd be taking a break around now. We happen to have the Chairman and all the Commissioners here and we haven't gotten any questions.

So, unless there is a problem, I would like to start off with some questions and, with all due respect to the Court Reporter who may need a break, try and keep this conversation going because this is really the crux of what we wanted to get to this morning.

So if we can just go with that alternative with some questions from Staff and/or if the Commissioners have anything to ask of the panelists, please jump in, too.

MR. PERLMAN: I have a question. I heard Mr. Thilly talk about a preference for infrastructure to help solve some of the load pocket issues. Within the scope of the solutions that each of you talked about, infrastructure was a component.

There's a point in time, I guess, in Mr. Bowring's proposal where you trigger an infrastructural approach on some sort of long term engineering scarcity analysis.

I guess my question is to each of you, 'how should the Commission take into consideration the idea of a policy that will incent infrastructure to remove the load pocket issues and how can it consider that in the overall way that it structures the way it approaches this issue?'

I'm not being articulate but I guess it's a difficult thing for me to say when you reach the point where you need to flip into that -- how does the Commission have that trigger set, if at all?

Roy?

MR. SHANKER: Two things. The more transparent solution in the comments that most of us offered to day was 'get the prices right' and the generation alternatives should be there.

I'm a little concerned with the perception that somehow transmission is differentiated absent a showing of market failure. That's why it's important to go back to that first criterion. The fact that something is more expensive as a solution is not de facto a purpose to mitigate or to price discriminate -- or to exert monopsony power.

If the alternatives are between expensive generation and expensive transmission and there aren't barriers it's telling you something. It's more expensive to serve load in these areas and at the margin -- that's the price signal we want to send.

A lot of this discussion forgets the fact that the existing resources that are relatively adequate to meet the existing loads as we are going forward and people have an opportunity to hedge themselves against those -- so what we're seeing is not some sort of rampant run up of prices for everybody, we're seeing an unhedged portion of load, people seeing the marginal cost of entry for transmission or generation.

Given that, there is a concern about how do you mitigate properly? That's always the second response after you get the prices right. We shouldn't run hiding from high prices if they're the right signal. This is Bill's -- you know, scarcity is good. Market power is bad.

As long as that signal is there coupled with the absence of barriers to entry, we should be happier with higher prices in those locations and the entry will be happy with higher prices.

MR. THILLY: We're not happy with higher prices in our location.

(Laughter.)

MR. THILLY: And it's not surprising that generators don't want a robust transmission system because it forces competition right down to the wire.

The trigger -- we're already there. Look at the statistics on transmission investment in this country over the last 15 years -- they're pathetic.

So I think the question is, 'how do we get it done?' If you step back, where is it getting done?

Well, one place I think we're somewhat successful is because we've had divestiture in Wisconsin. We have a company that can build transmission only that cannot be involved in generation and the only way it grows its business is by construction.

It's got a 10 year budget of $2.8 billion, quadrupling the rate base, far in excess of what was planned when it was owned by the individual vertically integrated systems.

Performance based rate making? We ought to reward those who have robust systems and take actions promptly to relieve congestion. We ought to penalize transmission owners who don't relieve congestion, focus it specifically on transmission.

We should avoid artificial barriers like arguing endlessly over whether a facility is for reliability or economics. The fact of the matter is, transmission construction to create a robust system benefits everybody in the load pocket. Let's get it done and move on.

There's a proposal that has been filed by American Transmission Company to address the real risks of construction, which is pre-certification costs over extended periods citing risk and construction work in progress when you have a major construction program. That will eventually lower the cost of capital and lower the cost to customers.

We need to find a way to enforce the obligation to build through RTOs and to get teeth into the planning and building process.

We need to create a system where people can get long term transmission rights from new base load resources, which is essential. All these incentives simply incent peakers which will result in a system that is suboptimum.

Finally, the Commission has the authority to take market based pricing away from transmission owners that don't solve constraints. I think there's significant teeth in that possibility.

MR. O'NEILL: Can I ask you a question? Is the reason why you're upset about the possibility of high prices in your load pocket because you're short in the market?

MR. THILLY: We're primarily a purchaser and being a purchaser in a load pocket --

MR. O'NEILL: So you are short in the market -- why aren't you long in the market?

MR. THILLY: I should say we have -- everybody has 18 percent reserves. All the fixed costs are covered in my market because of regulation.

But the exposure, first of all -- the $64,000 question is whether we're going to be covered by FTRs in this market. If you're not, you're exposed. We certainly don't have a guarantee that we're going to be covered by FTRs and no way to hedge new long term resources.

MR. O'NEILL: So your exposure is whether or not you get covered by FTRs?

MR. THILLY: That is a big part of it.

MR. SINGH: Also, you suggested that transmission is a better solution but if you have a load pocket where the constraint binding only a few hours a year, you're not suggesting we should build transmission even in the old days when there was a trade off between generation and transmission?

MR. THILLY: I'm talking about areas that are significantly constrained.

MR. O'NEILL: We solved the problem of incentives I think in the gas area by basically contracting out all the FTRs, if you will, to the non-pipeline companies, to the LSEs. That way they couldn't benefit from any of the congestion rents that may have occurred on their pipeline system and certainly had then all the natural incentives to expand the system.

Would that work in electricity?

MR. THILLY: It might. I thought about whether you ought to require somebody who's benefitting from scarcity pricing and has generation on both sides and owns transmission -- to divest some of their FTRs so they don't have the benefit of those FTRs.

MR. O'NEILL: In gas we basically separated the LSEs from the transmission owners.

MR. THILLY: In my market, of course, we've divested transmission and everybody's unbundled. But what you have is very significant concentration on ownership and control of the generation and concentration that is increasing -- not decreasing.

MR. O'NEILL: Do you see this as a temporal problem now that you have independent transmission?

MR. THILLY: I think if you give us five years and we've constructed major new coal units of which the fixed cost recovery is guaranteed for the life of the units by state regulation, it's been put in place so there isn't any risk -- and we get the build out on transmission that is in the process of going through the certification process, we'll have major steps and I won't have the same concerns I have today.

MR. KLEIN: Could I also respond? I work for a generation owner that's actually near that load pocket. We're in sort of a glut area and we'd like to get into that load pocket.

We actually, as generation owners, would like to see some transmission built but we also view it as important to do it in a way that first has the prices right.

I don't know how you would measure a performance based rate on how well the transmission company reduced congestion if you didn't know what the congestion was in the first place.

Certainly the experience in LMP markets in PJM with Delmarva is sometimes they're actually very low cost solutions to relieving transmission constraints, like upgrading key bottlenecks and transformers that are the key bottlenecks on the grid that actually don't require multi-billion dollar investment programs by the utilities.

So it's quite possible that you actually go to LMP in Wisconsin and you don't get such high prices at all on -- certainly, I don't think that it's so much higher necessarily once they go to LMP than the areas outside.

There will be transmission congestion during certain times but I don't think it's as persistent.

MR. O'NEILL: Are you saying there are cheap fixes?

MR. KLEIN: There may be.

MR. PATTON: One quick point that I think is important to recognize is that we all support the infrastructure solution. I think virtually every economist that talks about mitigation says structural mitigation is the most effective.

That's building transmission and generation, decreasing concentration. I think the critical question is 'how much?' If you think about investment in infrastructure, how much of that investment can be private and how much has to be either compelled on the regulator venue or more recently thinking about having the RTO essentially being a counterparty for a contract to build something on behalf of the load in there.

The real question is, 'how much of the investment has to be put on this side?'

The first preference of just about everyone would be to say, "where you can set up a market that sends an efficient signal, that becomes the basis for the long term private contracts that can be used to finance investment."

That's superior, to make the deliberate choice for certain other types of investment that can't happen and then to try to employ logic to try to employ a criterion when making those investment decisions that is consistent with how a private investor would approach it -- in other words, 'don't invest in non-economic projects,' just because you have somebody you can pass the costs to.

MR. BOWRING: Just to add very briefly, the Commission already has in place for PJM and I assume elsewhere a policy of how to trigger transmission investment to address congestion. Our point in the auction, and I think it's consistent with what David just said is that we have to make sure we have a market evaluation heads up on generation against transmission against demand side resources and in fact a significant incentive to do the auction is to ensure that we don't build more expensive transmission than the generation alternative would be.

It may well be we're building -- even Roy's high-price generation would be cheaper than building transmission. We need a systematic way to ensure the market gets evaluated.

MR. COLEMAN: That's really my question. I understand what both of you are saying but if we were to rely on scarcity pricing, for example, and somebody built enough generation to relieve the scarcity, would they still receive scarcity pricing going forward now that the constraint is gone and, if they wouldn't, why would they build it? Because the price point that they're building towards has now been eliminated.

So we have to have a regulatory policy that. like you said, puts in place the appropriate incentives to meet the goals and that's something that your feedback would be very helpful for.

MR. SHANKER: There's something of a "Catch-22" involved in all this when you start to say, "Give me a chance to build enough, put enough transmission in and enough generation in to suppress prices -- then I don't have to worry about this."

That shouldn't be the goal because then, what we're doing is assuring that there's never going to be a world that anybody under private investment is going to put a nickel up to the extent that they invest other than on a bilateral. They have no confidence that the market won't undercut them by some sort of a socialized investment.

It's too simple.

Again, this is a transitory problem and Roy's concern is that there are load pockets that cannot be resolved at any cost and only by this intervention we are setting ourselves up for the need for a permanent solution to solve this problem.

Benefit is only some sort of transitory issue of people getting over the threshold of pain. Then maybe it isn't him. Maybe it's not his customers. But the question is, who pays?

Is it somebody who located resources outside the load pocket because it's cheaper to build and was essentially getting free or socialized redispatch for a long period of time without paying for it and is now being confronted with those costs?

Is it somebody who's going to enter into a bilateral to sustain it?

Is it somebody who found it's cheaper to build other resources, and we saw this in the Delmarva Peninsula -- somebody had six years to build -- they built. They built in the wrong place. They said they did it because it was cheaper to build where they wanted to build rather than where it would relieve congestion.

These are complicated questions that go back to is it a persistent failure or simply somebody trying to avoid higher costs or reassign those costs through regulatory mechanisms to other people?

When you facilitate the latter you destroy the market because no one will then invest.

You've got to choose. If you want it to work as a market mechanism, these vehicles that you implement have got to be consistent with that down the line.

Well, I'm going to sit back. I'm not going to tell anybody to invest, I'm going to say "because you can't count on anything." It will be a regulatory call by the person who isn't hedged and he'll exert pressure to get somebody to enter into a long term bilateral that would be socialized across the market and cut down the prices where you['re trying to make a profit on your investment.

DR. HOGAN: I'd like to endorse what Roy said and say that David's question, which comes up a lot, also contains the seeds of an answer, at least a partial answer, to the question.

What you were identifying in there was a market failure. And it had to do with "lumpiness." If the generator was so big or the transmission investment was so big that before the fact there was expected there to be a lot of congestion and, after the fact, there wasn't any -- and so it wouldn't support it -- if that is the situation, the only way to do it where other alternatives are much more expensive, then I think you're in a market failure problem and you need some kind of regulatory solution to that, like socialization of the costs of that and putting it in the participant kind of funding framework mandatory.

But if it's not that, or there are other things which might be a little bit more expensive, ex ante -- who knows, given these engineering cost estimates and so on -- I would stand back and say "no, there is no market failure" because, if you can make small investments along the way then you don't have this big impact that you're talking about and you can make money on the small investments and recoup them over some reasonable period of time and you can let the private market do it.

In order to avoid the kind of problem Roy's talking about where you pre-empt the market and you insert yourself into having to solve every problem, which is right where you're heading if you don't do that -- then this is the demarcation -- what is the rule for deciding when there is something that requires that regulatory solution?

I think that's basically "lumpiness" in the sense of big scale -- it's the only way to do it. There's only one site in San Francisco and that's it and you have no choice -- or something like that.

Those are pretty rare circumstances I would argue and I would look at them very hard. Then, after you look at them very hard and you've convinced yourself that was the only thing you could do, then you get into the regulated world where you're trying to do that.

But I would lean against that and say that, "if it's not the case, let the market solve that problem" because you don't have the situation that, ex ante, the cost of congestion is going to disappear.

It might disappear ex post -- tough, okay?

Because, as Roy Thilly says -- translating it and saying it slightly differently, 'you have no right to preserve the rents.'

Competition comes in and something else happens and you get surprised and you make an investment that didn't' work out? It didn't work out. So you lose money and that's the discipline that's supposed to be there.

But ex ante, when you're doing this analysis, if you can't see that that's going to happen for sure, then let the market solve the problem.

Say you compare transmission and generation in discussing "lumpiness" -- but is there a difference? Because I think to find congestion in a particular interface and then rely on market signals is one thing.

But when you go over to the generation side and you talk about scarcity pricing to rely on OP-4s, any time I can have a signal above what Joe calls the "competitive level short term marginal cost" in a time of shortage -- is that realistic? Does that have implications or concerns for or with reliability today, and so on.

PROF. HOGAN: I was trying to address the particulars of David's question. The problem of 'we desperately need this plant to run but you can't make money running it' -- that's sort of the framework for a lot of this conversation -- is a signal to me that there's something wrong with the market design.

That's what David Patton has gone through as examples of, and others, to sort of fix it. He has the five steps, the best way to do it, then the next best way to do it and so on -- until you can get those price signals right.

Now, there may be situations where you can't fix it. You don't know how to fix it.

An example in the present framework would be where you're providing not capacity, so it's not an operating reserve problem and not energy and so on -- it's basically reactive power and we don't price reactive power.

So my answer is, 'price reactive power.' But that's another leap we have to go through and, until you can do that, the other solutions don't work and you have to do something else.

But I think these are pretty rare actually. I think if you focus on the market design questions and you get these scarcity pricing and opportunity cost pricing correct theoretically and in practice, most of these problems go away. That's my belief.

MR. PERLMAN: How do we measure that, though? I think there's a lot of appeal to what you're saying -- as soon as you raise the prices you fix the market design -- as David Patton has suggested.

And then you guys say there's not enough certainty of revenue because it's volatile -- or something like that -- and you don't get the expected investment to address what you've put in place.

Do you just say "we've done our job because we've given the appropriate price signals even though the financial people won't react to it as we would expect rational economic people to do?"

Is that the extent of our job? Do we have to associate what we're doing with the expected outcome?

Or should we do the best we can in an market context then let the market sort it out?

PROF. HOGAN: My answer to that question, if you're directing this to me, is I would look very hard at these market failure problems, try to get the market designed as well as we can do in that and then, unless I can come up with some explanation about what the failure is, like the "lumpiness" explanation, to lean toward the market.

If it turns out that I've put all these things in place and the prices are going up, then Wall Street says "we're not going to invest unless you pay us this very high cost of capital."

I think there's a message there which is that it's risky to invest in this location going forward.

Maybe that's a good idea -- not to invest. Having you do it doesn't remove the risk. It just redistributes it.

Unless you can show me some reason why we're creating risks that wouldn't exist otherwise and that would be the "market failure" kind of problem -- but if the problem is we don't know what the congestion is going to be int his region for the future because lots of things could happen, well, that's life.

So maybe the right thing to do is to do a lot of short term fixes, recognize that prices will go up and people address demand.

Roy's not happy with this but shut down those aluminum plants in the Northwest and go someplace else.

(Laughter.)

PROF. HOGAN: I understand that. I'll be happy to do it without giving the same answer but it's not obvious that that's not a message -- that you shouldn't invest rather than, Oh -- if you know what investments we should make and you are sure, do it.

But don't bother with electricity restructuring.

MR. PATTON: A couple of thoughts I'd add to that.

I agree 100 percent with the notion that these investments are not nearly as lumpy as people think they are when they think through them.

In most cases what happens when you see generation being built is not that the scarcity is huge and then it goes away.

What happens is you go from 25 hours of scarcity to 15 hours of scarcity -- it's equilibrium that the market is searching for there and you can't overbuild.

And I think one thing to recognize in terms of the scarcity pricing signal is I don't believe the financial community is looking for stability in the spot price. They're looking for stability in revenues that a generator can make.

A highly volatile spot price will lead to an attractive forward contract market for the generators so the threat of price spikes and shortage on the spot market, assuming they're efficient, will then lead to new generators being able to sign contracts with either loads or others and bring those contracts to Wall Street.

They're not going to show up with a forecast of what they're going to make selling their power in an hourly spot market and hope they get financed, I don't believe.

MR. BOWRING: I beg to differ by what's been said by the last couple of speakers. It's fine to talk about scarcity pricing and it sounds like it makes sense from an economics perspective, but tell me exactly what that means in a load pocket where you have all the generation owned by one generator, where you have more than enough generation -- you have twice as much generation as you need in order to serve load in the transmission -- what does that mean exactly?

It means pricing at marginal costs. There is no scarcity in that situation. If you get to the point where you're scarce it's also fine to say we should let people decide not to invest. We can have shortages and everything will work out in the market.

I don't think that makes a whole lot of sense in a system where ultimately you need to have a reliable supply of electricity.

Finally, what I would add is, that you certainly need to have a market mechanism to evaluate those risks but simply kind of falling back on the term "scarcity pricing," I think needs to be examined very carefully before one simply says that scarcity pricing is the solution.

MR. PATTON: You "beg to differ" but I didn't hear any difference.

(Laughter.)

MR. PATTON: I don't think anyone is suggesting shortage pricing where there's no shortage -- in your example, you're right. If there's a surplus, the fact that you've put in provisions that would reflect the value of foregone reserves when you can't hold your reserves, those provisions would just never set prices in a pocket where you have a surplus.

MR. BOWRING: But ultimately your scarcity pricing is administratively set -- how are you going to let the market determine what that price is? Even in the aggregate market you don't want to let the bids determine the price. I would assume the same is also true in the pocket.

Again, you have to have a defined reserve under your fist option and then somehow a market overseer would set the price.

MR. PATTON: I don't agree but accusing it of being "administrative," and that somehow is a bad thing? Because all these markets have operating reserve requirements.

The only thing that constrains how much PJM or anybody else will pay to maintain their reserves is the thousand dollar offer cap.

If there were $2,000 of electricity available from Canada to New York we wouldn't buy it because New York has said "there's a $1,000 offer cap." So implicitly your reserves can't be worth $2,000.

Carrying that through in terms of what is the demand for operating reserves doesn't have an economic value -- let's stop pretending that it doesn't.

You can say it's administrative but it is logically consistent with everything else that we do in these markets.

MR. BOWRING: It's fine to recognize it as a value. The question is, is there a market mechanism that can elicit that value as opposed to somebody setting the price?

MR. O'NEILL: Isn't there a self-correcting mechanism for scarcity pricing that, if you get it too high, the buyers can bid into the market and counter the scarcity pricing?

MR. BOWRING: Yes.

MR. O'NEILL: So there is a self correcting mechanism?

MR. BOWRING: I'm sorry you have to say that again.

MR. O'NEILL: If you get the scarcity pricing too high the buyers in the market will recognize that and bid into the market and that will be a self correcting competitive answer.

MR. BOWRING: Did you find that satisfactory in California?

MR. O'NEILL: Yes.

MR. THILLY: Can I just back up a little bit? The facts are so important. A lot of the argument that I'm hearing about generators getting entry, the price scarcity and price signal inspiring that -- where I live the driver for the construction of generation is the retail ratemaking and the state policies that provide for the recovery of fixed costs over the long term for rate base.

We don't have any RTPs that are going to come in the market other than under a long term contract with one of the existing investor-owned utilities so it doesn't change market share at all or create competitors.

So I think those differences make -- they mean a lot. You have to recognize that when you've got these sort of global solutions.

MR. SCHNITZER: I want to make a point in between the dialogue that just occurred. I've agreed with David, I think at the FEMA panel, that this pricing of operating reserves on a locational basis makes a lot of sense.

That isn't going to eliminate the need for potential mitigation in those markets because you can still have highly concentrated ownership of the people who can provide those reserves. That's the exchange that was just happening here, the fact that prices aren't clearly high enough to keep people from retiring capacity when you need it is a symptom of the problem.

We can have a pricing mechanism to help correct that but that doesn't mean there isn't going to be a need for mitigation there as well if we have concentration and, I think, for a lot of existing -- of the circumstances that I spoke of and that Joe spoke about where you don't have scarcity, you have enough generation and transmission to be over the problem but you've got some potential exit issues. You're going to find a high correlation where you've got enough concentration in that load pocket that you're still going to have to have some sort of mitigation of capping or over capping or whatever, even with these enhanced reserve markets, which I think we agree would be better than what we have.

That isn't quite to say, "you know, let's just go to $1,000," necessarily as the right answer in that world, that's number one.

And going all the way back I think to that Roy's original question -- I remember Bill hosted a session over 10 years ago where former Commissioner Stalon basically observed -- "would it be so expensive to just make the transmission system unconstrained?" Remember that?

This would all be a lot easier if, in fact, it was always quick, cheap and easy to remedy transmission constraints. The fact is, it's none of the above and so, in everything we do, there is and needs to be an economic component. We shouldn't have, as a command and control goal, to eliminate congestion, to eliminate transmission constraints to eliminate load pockets uninformed by the economics.

Whatever we do has got to recognize those economics and, as the speakers alluded to on either side of me, "if not, what are we thinking about in terms of competition and generation anyway, because we will have killed that."

MR. BANDERA: A follow up on the distinction without a difference between Joe Patton and Joe Bowring before -- they both agreed that, when there's a surplus situation and it was concentration that allowed someone to have market power, they both agreed that mitigation is appropriate under those time periods.

It sounded to me that before, competitive prices should prevail under that time period, that competitive prices is the marginal cost of the least efficient unit.

I was wondering if everyone agreed with that type of approach from mitigation under those circumstances?

MR. PATTON: There's two things there.

In general I would agree with Joe. Whether it's cost plus-10, whether it's some conduct and impact that's defined by a tolerance band, when you have a surplus and concentration of ownership, you're not just looking for this pricing. You're also looking for withholding. That goes part and parcel with it.

But the other side of why it is desirable to go for the scarcity pricing is because now, when that does trigger, when we do see those opportunity costs, the mitigation almost becomes trivial because that offer price isn't going to be setting a price any more. They're going to be looking against where you are in the reserve violation and however we've come up with it, the $1,000, whether it's the opportunity cost of the shadow prices of some constraints we're seeing that are binding external markets or whatever -- I'm bidding whenever I could and it's irrelevant at this point because the mechanism for mitigation is now saying "the right price is blank" and that's what it's going to be. It makes things a lot easier.

These two arguments sort of disappear once we get the other pricing mechanisms in place.

MR. BANDERA: So we're talking about a regime where there's bid mitigation that restricts bids at times to marginal cost type proxy -- whether it be cost plus or the amp type.

MR. SCHNITZER: My answer to that would be "except in category two."

If you've got an answer where that reserve market is only a small number of the hours of the year and that unit's a contributor, it's there for when it needs to clear that reserve margin and when it's there, there's enough and there's some surplus.

And when it's not there, it isn't. I don't think marginal cost plus ten percent is going to do the trick necessarily where the whole market is oversupplied and there's no ICAP revenues to speak of.

MR. SHANKER: Then there should be some sort of a locational agreement or the opportunity costs for the locational reserve violation of those two hours is huge. It's one or the other.

MR. SCHNITZER: But again, you can change the labels but you're still going to back yourself into the fact that, whichever market it is, it's concentrated. So if it's locational ICAP market, you don't want that person to be able to bid new entry prices if you don't need new entry.

You can have that in the ICAP market. You can have it in the locational reserve market. You can have it in an energy market, but it's the same problem. You've got enough right now.

But you have concentration in terms of who can offer it in terms of which every set of markets you recover it from don't disturb the underlying fact that there's excess or surplus and there's concentration and you have to deal with that.

MR. SHANKER: That starts to sound like a failure and if it starts to sound like a failure it may be that that unit should not have been divested, or if divested there should be some sort of compensatory structure for the whole.

Looking at both fixed and variable costs, we can always talk our way into "there isn't a good mitigation strategy or pricing strategy if we predicate a market failure."

David just drew a little circle earlier. If we get to a small enough situation, something that is physically unique, a single generator in a specific location where there are probably significant barriers to entry because of the fact that they are always needed, then you are probably going to look at a solution that is not predicated on markets, at least not as fully dependent on market price and has a significant administrative element to it which says "let's try and send the best price signal we can, take a look at what's missing and pay the rest."

MR. SCHNITZER: I don't think even in the circumstances I was referencing that you can't rely on offer caps of some sort. Just saying that they're going to be $1,000 or new entry by default may not be the right answer in those circumstances. There may be a bunch of those and they may be persistent.

But I think that's an indictment of the whole market based system. I agree with what's been said here, that we ought to stick with offer caps as opposed to price caps or other contractual arrangements where we can.

MR. THILLY: Can I take a moment to just respond to Michael's question about transmission? I'm not suggesting that you don't take economics into account in building transmission. I'm not worried about overbuilding and I don't operate under the illusion that we really are going to get a robust system that eliminates all load pockets.

But we can get a lot closer than we are today.

What's key is, we've got to recognize that there are many more and more difficult barriers to the construction than building a peaker or a combined cycle generation unit.

The planning process is complex. It has to involve a number of different parties. It's got to balance needs. It takes a lot of time. It's transmission facilities have to meet multiple purposes. It's not a simple world.

We increased import capability in Wisconsin about 3 or 4 hundred megawatts in the last year and a half. The result has been creation of many internal constraints between the control areas within Wisconsin.

Hard -- state siting issues are much more complex on transmission than generation. Then we have a number of players who would be hurt by the construction of transmission and who have a lot of power.

So we've got to take a different approach than just simply saying "compete against the construction of a peaking unit." That's not going to solve or problem.

MR. TIGER: Perhaps to get back to some of the financial point of view, we've had a lot of discussion about the energy price to go back in the financing markets today or going forward in the absence of a contract, regardless of the level of whether electricity, the energy price, is mitigated -- will you get new entry into load pockets solely based on volatile energy prices -- as a first question?

MR. NAPOLITANO: This will be a generalization but the capital that is sophisticated enough to understand the conversation that just occurred, to quantify what was just said, to price-risk of what was just said and decide to bear what was just said -- that capital is currently funding other ways to make money than electric generation --

(Laughter.)

MR. TIGER: That said, right? What may be of David's five elements and here we're predicating that you actually need new generation in a load pocket, what would be most amenable to capital actually committing to that load pocket --

MR. NAPOLITANO: Several of the gentlemen throughout the course of the conversation really have brought out some of the concepts we have started with, separating fixed and variable risk and return on and return of capital -- one of the comments I made in my remarks was, debt learned a lesson the last time when they took equity risks -- it doesn't want to do that again this time.

We all understand that debt is the cheapest cost of capital in the capital structure to aim at these solutions and a lot of the conversation that has occurred has really talked about the revenue in the market as opposed to what an investor will look at as a forced cost to decide whether they want to bring the capital or not.

Debt goes first then equity is going to have to do some sensitivities to decide where its tolerance is.

So there's a minimal cost that equity does have to get comfortable with and the tension is between that implied cost and where all of these mechanics on deciding revenue line up to see if there's a positive intersection point.

But I'd argue without the debt the equity becomes a lot more interesting because of your saying it's only equity that can invest in this market -- you've got a cost of capital that just doesn't work for something like infrastructure.

MR. BALIFF: I think the thing we're not also taking into account is again the cost of building in these load pockets. We can talk about whether the market signals are there but you can't leave out the nature of the construction, right? The nature of the construction right now, at least in my experience in the three or four projects we're trying to build in New York, Wisconsin is almost unknown when you look at projects that very sophisticated people who understand construction are seeing two times the cost in the eventual price -- you're talking about not being able to get the equity sponsorship first and, as Frank talked about, in order to analyze this for debt, there's just so many more opportunities to make money -- when the investors, whether it be taking place on regulatory risk in California and buying the debt, the distressed debt of some of the utilities there, there's just better and easier ways and more certain ways to make more money.

That's really I think the bigger issue.

That being said, there is merchant risk being taken today. The SES transaction I keep going back to is about to get financed in the next two weeks. There is a merchant risk there. That contract is only 10 years and that contract, if people get the next present value, is a pretty long contract in today's world. That still cannot finance the asset, the cost of the asset is just too high. It's around $2,000 a kilowatt. That's a coal plant in Arizona, okay?

So when you finance these plants in load pockets there's going to be a certain amount of merchant risk -- what you call an amount of volatility risk -- that is primarily being taken by the equity and it monetizes itself by how much equity is available in the capital structure.

There is a way possibly from a regulatory standpoint -- I think New York thought that the Liberty Bonds, for example, would help finance these types of infrastructure. I can tell you that will not happen.

Liberty Bonds have a prerequisite of being investment grade -- right now to get an investment grade rating from the agencies and, by the way, we haven't even mentioned the rating agencies, okay?

And you know Frank and I are trying to follow along, both Frank and I have I think Master's degrees in engineering -- we're trying to follow these agencies.

Forget about the agencies -- they're taking a very different view. You're really looking at very sophisticated, what we almost call the "leveraged market" -- high yield investors looking at these merchants and Frank introduced it with a very good comment, "There are better ways to make money elsewhere."

MR. SHANKER: The conclusion on this though should be that everything you do to reduce the risk of that hides the price of that to the people who are consuming at the margin, in the load pocket. That's what's disturbing, the fact that someone is coming in and saying "yes, I really need that five-year contract or that eight year or 10 year contract" -- to make it work.

The question is, 'why isn't the load in those locations willing to step up to that obligation if that's what's necessary?'

And if they aren't what are we doing to diffuse the information such that you're sitting here and we're undercutting the market potentially by taking an action on an RMR agreement that somehow socializes those costs -- so that we can keep people from seeing the fact that it might be a $2,000 a kW in-city unit.

That is ridiculously expensive, not because you can't enter the market but because it's ridiculously expensive in certain locations to build. There's nothing wrong with that. I'm not troubled by the fact. I mean, there's a lot of things that are expensive in New York. Almost everybody that lives in this area knows, to replicate your housing in New York, you pay five or six times more.

It's not inconsistent with that to say "yes, it costs two or three times more to provide electric power where it is needed for reliability inside the city."

The question is, 'do you want to set up policies that hide that fact from anybody's consumption?'

MR. PERLMAN: A question that I have for you -- I understand what everybody is saying here, what Mr. Thilly said about "associating the retail regulation with the wholesale regulation" in making all this work seems to be an issue to me.

In a lot of the markets we're talking about, the distribution utility is a default service provider with maybe a one-year RFP or something like that and they have, as far as I can tell, no incentive to enter into any kind of long term contract -- in fact, they have a disincentive in the retail marketplace from a regulatory perspective because they're trying to incent retail competition and the retail service providers don't have the balance sheet to do this nor do they have the customer base going forward.

So we're stuck with the situation where the price signals you're talking about may incent a rational LSE to do this if they weren't stymied by other types of regulatory incentives and were stuck in this betwixt and between world.

These guys are saying -- what they're saying and the people whom we would expect, all other things being equal, to sign the contracts won't do it because of their other incentives.

I don't know where we go from there but that's I think pretty much what we are seeing today in a lot of places and it doesn't mean that any of it is wrong. It just needs to fit together and I'm not sure it does.

Do I have that wrong?

MR. BOWRING: I think the institutional issue you identify, particularly as we move away from integrated utilities where the transmission owner and the LSE are the same company -- you've identified exactly a really significant institutional issue and an incentive issue going forward -- that is, LSEs will not be and are not now long term entities.

Therefore they are not going to be there a long time. There's no guarantee they're going to be around a long time. Not only do they not have any desire to enter into long term contracts, but they might not even be able to financially. That's certainly an issue.

And then it links back to the financial question because, while what Roy said is certainly a fair conclusion to draw, that the risk needs to be priced into the value of the power in the load pocket, it's also the case that you need a transparent, really straightforward mechanism, which is what the investment folks are telling us, that shows people they can make enough money to cover the costs and will there fore actually invest.

We don't want to be creating, adding, regulatory risk -- neither do we want to be suppressing it.

MR. THILLY: There's another element to what you're talking about that makes it even more difficult. In my area, if you have a utility that has part of its service in a load pocket, say the Upper Peninsula of Michigan, which is even worse than where I am, and a lot of territory not there -- they, on a retail basis are going to average their nodal costs and the folks where the real problem is are not going to get the signal.

The only entity that's going to get the signal is the small municipal entity that's already there. That creates a tremendous equity issue, I think. The signal doesn't go through. The people consuming don't get the high price signal we're talking about but the generator gets the high price.

MR. HOGAN: I think this is a great opportunity for exercising regional deference --

(Laughter.)

MR. HOGAN: -- so the need to match wholesale and retail is certainly a legitimate issue and you want to make sure you're not doing something which precludes people from doing whatever they want to do on the retail side.

But I don't think that that translates into "it is the job of the federal regulator to undue what the state regulators are doing with their retail regulation."

If they choose to have a big zone in the state -- I wouldn't recommend that they do it, but I would also even more strongly recommend that you not try to undo what they just did -- because they chose to do that there.

If they choose to have not a core-noncore market, but to have all retail customers dealing with the marketplace and LSEs who last for six months and they keep switching back and forth, that's their choice.

I wouldn't do it that way personally but that's their choice. I don't think you have to undo that and I think if you have a viable wholesale market to design, and the property rights that go with it and all the other kinds of things we've been talking about here, you can leave it up to them to decide.

Some of these customers are big enough so that they can internalize these problems and they'll contract and they'll deal with the problem.

The munis that actually have load serving obligations will go contract if the property rights are there -- that's an issue that you have to worry about, making sure that they can get those things.

But I don't think you should be worrying about problems like really bad retail design in the state. We have to change the wholesale market design in order to undo what they're doing in the state because I think that's a quagmire that you're never going to get out of.

MR. COLEMAN: I'm not suggesting that. The only point I was making is that what we're hearing is, if you stimulate pricing, the LSEs may contract. But if there's some intervening state regulatory program which may be fine -- I don't think we should tell them to change.

MR. HOGAN: Then they won't contract.

MR. PERLMAN: That's right. Have we achieved our goal or should we care?

MR. HOGAN: You shouldn't care.

MR. SHANKER: All you do is drive the risk up because the guys on that side of the table are going to place a price on doing this that's going to even be more expensive.

We go through this discussion and you've probably heard me a lot say that we shouldn't let the retail tail wag the right price signals at the wholesale levels of the wholesale dog -- we go through this all the time.

We do lots of really weird things in wholesale market design to accommodate bad retail design and, if the net result of that is that retail regulation is increasing the risk of wholesale capital formation, but we're out of the way of it, that's the way it comes out.

Otherwise you just cascade. If you want to stop that then you're going to say "I'm going to tell you what the right place should have been" despite the fact that they've got this bad design and the only way you're going to be able to do that is you're going to step in and start contracting.

Who are you going to contract for it? You're going to contract with the retail customers via the LSEs as the ISO or the RTO -- we're going to be back in central planning and we're going to get rid of the market.

If you want that solution, we should step back and do a whole bunch of other things consistent with that, as opposed to piecemeal pick out stuff that will suppress price.

If you want to do it, be fair and compensatory across the board and say "I give up," but to sort of cherry pick and say "I'm-a going to mitigate or control costs" or suppress price in one area where there is a true price signal coming through, but it just isn't "acceptable" and the retail programs don't work with it -- this isn't really viable long-term. It's a disservice to everybody in the market.

MR. GRAMLICH: Could I follow up and maybe get some other comments on that? It strikes me, if there is scarcity in a load pocket, investment is needed if the LSE for whatever reason is not making the investment, Roy put out the theory that the alternative is the RTO and I think we're seeing that proposal in various forms crop up in a few of these markets, going back to kind of the original concept of an RTO and ISO.

Is it an appropriate role for the ISO to be in that position? You've been doing this for a long time.

MR. HOGAN: I will argue that, no, you have to talk about what the alternatives are but I think, just as Roy said, it's the slippery slope problem.

You just inevitably are going to get into -- that creates incentive which creates more problems that you have to intervene and pretty soon you're doing everything.

Unless you can find some way to define a principle at which you're going to stop -- I don't know how to avoid that problem.

If the customers are just not going to do contract and they're just going to live with high and volatile prices and shortages and lights going out, I don't think that's consistent with the notion that we got the market design right and the scarcity prices are correct and there's no generation that's prepared to go in there.

It might be better if customers did it on their side -- it might be easier and so forth, but at some stage, the generation's going to go -- and I'll invest.

(Laughter.)

MR. KLEIN: Rob, I'd also like to respond a little bit on this because I think the Commission should be encouraged by what is going on in New York City, which is the one area that was on the top of David's list where all the market design elements are ripe for a load pocket.

You know, there are projects that have gotten built. There's East River Repowering, Ravenswood Four, SES and one of the most innovative projects we've seen is a merchant DC tie, Conjunction, which is bringing 1,000 megawatts from Upstate New York down into New York City and is able to do that on a merchant basis in part because all the market design elements are right.

It's also the case that there are probably 10,000 megawatts of other projects, some of which are not getting financed in New York City -- maybe what we're seeing is the right result when the market design is right and New York City is really just about the only place where it really is right for a load pocket according to David's list.

MR. PATTON: Let me modify and just say what I said about New York City --

(Laughter.)

MR. PATTON: It was -- its the only place where they're attempting to do any of the first three items on the list. They're certainly not doing the first one. But they do have the locational ICAP which is helpful.

MR. THILLY: I can't help but respond to the position "we should ignore reality." The first thing I said was "you've got to pay attention to the facts" and ignoring the retail reality, the economic drivers and the facts in those situations because somehow we think the retail system is bad results in implementing this in large parts of the country and in the imaginary world that exists on paper, but is not going to produce the results that you want.

If the objective is net benefit to customers you've got to design a system that's reasonably likely to produce that for customers and not just simply ignore those folks that are in states where you think they've got a bad system.

I don't think that results in a just and reasonable rate in those areas, the wholesale which is the Commission's obligation --

MR. GRAMLICH: Roy, you don't disagree with the idea that it should be the load serving entity's obligation to make the investment, do you?

MR. THILLY: No.

MR. GRAMLICH: Your state certainly has the ability to do this.

MR. THILLY: I agree.

MR. GRAMLICH: You would not support the ISO 30 RTO negotiating and signing long term contracts.

MR. THILLY: No, I don't like that model. I'd much rather do it myself.

MR. GRAMLICH: On the institutional question, I think you all agree, or most of you agree.

MR. HOGAN: If Roy is referring to me, saying we should ignore the retail, that's not what I'm saying. I'm saying there are things you should do that are under your control that are extremely important to do because you want to support the retail markets, like getting all these design issues correct, like the allocation of the property rights and the FTRs that he's legitimately worried about -- make sure that's done well so that you can go forward. You've got all the other problems in setting that thing up.

But after you've set that up and you give them all the opportunities to participate in this, if they decide they're going to give away electricity for free, if they're going to stop, take all the meters out and they're just going to let people consume because it's better because it attracts industry, I don't think that you should just say "well you know I guess we just have to solve that problem for them somehow."

If that's the choice they make they should live with the consequences of that.

So there are a lot of things you should do so you don't ignore them but you don't have to undo things that you don't like that they're doing and then torque the design of an efficient wholesale market in order to correct for the things that you don't like that they're doing.

MR. PERLMAN: Can I ask a locational ICAP question? Does locational ICAP raise questions of locational market power if you end up with a situation where the entity that is in the location has some kind of concentration issue -- and how do we address that problem and not blunt the price signals that the locational ICAP is designed to create?

MR. PATTON: I don't think it creates the problem. The problem exists no matter what you do. In any of the alternatives, if you have somebody who is the dominant supplier of capacity in that area they can create high energy prices, high capacity prices -- I think what you want to do to mitigate that in the locational capacity context, I think the demand curve for capacity is very helpful, not allowing people to withhold the capacity.

In other words, if I need 1,000 megawatts in some area, you need a system that recognizes how much you have and doesn't allow a supplier to make you believe you only have 800 megawatts by withholding some of this capacity.

So it's a problem that's much more acute in the locational ICAP. It's also a problem that you confront in broader capacity markets although not as severely.

MR. BOWRING: Could I just add, given that I think that all capacity markets have almost by design market power issues, it's certainly the case as David said that although the local ICAP doesn't create more market power it certainly reveals it as you move to a small area -- there's absolutely no question you're going to have extreme market power and selling capacity.

That's why, rather than basically setting a price, a local price, which is what local ICAP ultimately is going to boil down to, unless you have some, again, market mechanism for example, which permits new suppliers when you need new capacity to bid against one another, for example an auction, in an market mechanism in order to reveal a market based price, I think the auction alternative has to be preferred to the alternative where you simply are setting a local ICAP price.

Unless I'm misunderstanding David I think using a demand curve or telling people what they have to bid if they can't withhold is effectively equivalent to setting the local ICAP price.

MR. BANDERA: Could someone explain the difference between what the demand curve for ICAP is versus sort of contrasating it, a vertically inelastic demand for ICAP? It seems to me when you define an ICAP requirement and say you're willing and that's the requirement, that's just an inelastic demand curve versus putting in place.

MR. PATTON: That's right. It's variable capacity. But most of the capacity markets at least when they began had vertical demand curves. So we said the requirement is the single point and the deficiency price is some price that we're going to cap the capacity price at. What the demand curve does is attempt to recognize the fact that an incremental capacity over the minimum requirement has a number of benefits so that for both reliability and the fact that it reduces the instance of a shortage on the market the effect it has is it changes the capacity suppliers' incentives because if they withhold instead of going from a price that's close to zero to a cap, the price effect is mitigated.

MR. SHANKER: Derek, you have two sort of fundamental problems with the capacity markets -- inelastic supply and inelastic demand. The demand curve is an attempt to make -- I want to say add -- elasticity on the demand side and to allow variable quantities so that you might be happier with 17 percent instead of 18 percent, pay a slight premium for that if there's a shortage.

The other side which people are looking at and you can do this and, to some extent, it's a variant of what Joe was talking about in the auction structure, is create elasticity in the supply side by creating a window that's wide enough for new entry and have people compete to offer on that basis and you can have both of them together.

You cam mix and match because fundamentally what you're trying to do is beat the market failing on inelastic supply and demand by giving an opportunity on both sides for a response.

MR. O'NEILL: Joe, can I ask a question? I don't disagree that when you need capacity it may be appropriate to conduct an auction. Why doesn't the LSE or the state oversee that auction?

MR. BOWRING: I don't have any vested interest in who runs it. I think it's important that it be run in an competitive manner.

The point David made earlier is that LSEs by design typically aren't in a position and don't have the incentive to do that. Maybe the state or some other entity -- it doesn't have to be the ISO but what it does have to be is an institution that has the ability -- you're not buying the capacity, you're not participating in the auction. You're simply acquiring it on behalf of the load and the load would be obligated to pay it.

The ISO was clearly in a position to do that but there's no reason it shouldn't be the ORT rather than the state.

MR. O'NEILL: In the white paper we sort of indicated that resource adequacy was a state issue and that the state was responsible for it. Why wouldn't it be the responsibility of the state or the local LSEs?

MR. BOWRING: Again I think there's a very good reason why it's not the local LSEs. We've set it over another --

MR. O'NEILL: Because the states chose a bad retail market design?

MR. BOWRING: -- I'll leave those words to be yours.

(Laughter.

MR. BOWRING: But nonetheless the way things are structured is LSEs don't have the incentive or perhaps the financial capability to enter into a long term contract so, given that and given that there's a need for a long term contract in order to provide revenue stability to generators to solve reliability issues in the load pocket in order to make them financeable, clearly there has to be some way of obligating load to pay the costs of the generation power for expenses if it is.

MR. O'NEILL: Is the reason why because they don't see the full cost of not hedging?

MR. BOWRING: Is the reason why what?

MR. O'NEILL: If you don't have the incentive to enter into long term contracts maybe the reason is that you don't see the full cost of not hedging.

MR. BOWRING: LSE wouldn't see the cost. LSE would simply be passing it through to the load.

Ultimately the institutional problem is there's not an entity in the market who is interested the same as the load.

MR. BALIFF: There's an important financial element to this, too.

MR. NAPOLITANO: When you talk about this relationship between the wholesale and the retail and the pocket you're really talking about who should bear this cost. Everybody agrees there's an incremental cost and furthermore what should that cost be?

One of the problems, when you have certain levels of retail rate disaggregation is, in the interim which we learned in California is, when it's not clear who should pay what, the only person with the working capital to do it in the interim period is the LSE until they burn out their working capital. Then it's too late to decide what should have been done before.

So you understand there's this tension between what the Commission can and should do and what the states can and should do. But there is a direct financial relationship between the two and capital won't step on either side of that equation until they understand how that relationship really flows.

But if it's complicated also by the rating agencies which are taking right now a very strict approach to these contracts -- as much as we also cover the generators we also cover the LSE -- the rating agencies right now take a very strict approach to these contracts and clearly make them debt equivalent.

Which is why you see many low capitalized utilities having very much lower ratings than you would think primarily because they have what you call "computed debt" from the rating agencies.

That's another reason why you're not seeing these contracts. There's a lot of uncertainty on that.

MR. O'NEILL: Is that new? Why hasn't that happened in the past?

VOICES: It has.

MR. SCHNITZER: People now have an appreciation of how out-of-market those contracts can be which they didn't before. But two points on the locational ICAP that I just want to come back to.

The first is there can be concentration issues as we've said that have to be dealt with in mitigation. The second is locational ICAP markets are not a full substitute for RMR and if you look at what people define to be load pockets and you ask yourself "is every generator within that load pocket electrically fungible from an RMR perspective" the answer is no.

Particularly with the reactive considerations you will have with subsets of generators or individual generators which have RMR conditions that are unrelated to the other generators in the load pocket there are some benefits and some improvements in the market from going to that concept, but you are still going to have particularly for reactive, you're going to have much more localized issues which raise their own concentration issues that are not addressed fully by the locational ICAP.

MR. PERLMAN: What do you mean by "must be addressed in mitigation?" How would you mitigate?

MR. SCHNITZER: I think you've got a couple of concepts here on the table. I haven't worried about the ICAP solutions so much as some of these other energy market and whatever solutions but I think you've got something short. The concepts I laid out or the principles that I laid out say "replacement cost is not the right mitigation" where you don't have scarcity in the load pocket and you have more than enough supply in the load pocket and you have concentration saying you can bid up to replacement cost -- is probably not the right answer.

MR. THILLY: Can I come back for a moment to Dick's question which had to do with whether the load serving entity has an incentive to do longer term contracts? I said I would like to do it and not have the RTO do it but my economics are, my driver is delivered cost of power to my customers, bottom line, which is a different set of drivers and economics than some other folks have and an obligation to serve state -- those utilities have got to have the capacity and meet the state reserve requirements or they're going to get hammered in the rate setting process so they do have an incentive to enter into those contracts which may not be true in other parts of the area.

So a 'one size fits all' doesn't work very well.

The biggest problem we have on those contracts 'easy to build a peaker -- very difficult for a small entity to get long-term baseload capacity.' That is a market where there is a lot of market power concerns and it is made even worse by the fact that the market designs don't provide long term FTRs for new resources.

I'm going to probably invest in a coal plant but it's going to be very, very costly.

The whole justification is the delivered cost in energy -- that's the only basis that's economic and if I don't have a long term FTR to go with it, I don't have it.

I don't know whether these guys will finance it because the economics is based on something -- it's speculative on that long term FTR. That is a huge problem going forward.

MR. MEAD: I'd like to ask a question about "must offer" requirements. We've heard several speakers address the issue of how to address economic withholding and bid caps of various sorts were suggested.

Is there a role for some sort of policy to address physical withholding? Is there a rule for requiring basically a "must offer" requirement? If so, what would the nature of that "must offer" requirement be?

MR. BOWRING: Let me just say very quickly in PJM one piece of selling capacity is selling a "must offer" obligation -- when you sell capacity to the market one of the things you're selling in addition to effectively a call at the market on your energy during emergencies is the obligation to offer that exists. It doesn't make monitoring physical withholding any easier and as anyone who's tried to do that can tell you, it's well nigh impossible -- it's at least very difficult.

Nonetheless there are basic metrics that one can track, including outage rates and availability rates and other things, that let you know whether you have a problem.

MR. PATTON: Clearly you have to address physical withholding, because if you mitigate economic withholding they can just accomplish the same outcome by physical withholding. So you have to address it.

I think thought that when you look at "must offer" if you define physical withholding on market power in general as the ability to raise prices above competitive level profitably, in this case by withholding the sources, that's really what you should be addressing.

What I find looking at these markets is that the vast majority of generators in the vast majority of conditions don't have the ability to raise prices. If you were to ask me, "is a generic 'must offer' provision necessary?" I would say no. What is necessary is a prohibition against physically withholding to exercise market power.

That may translate into effectively a "must offer" provision in two percent of the hours for a certain generator and not 100 percent of the hours. In those cases they can derate their unit and take it off line. They can shut it down for a season and it won't have any measurable effect on the market prices.

If that's true it's okay and it's not physical withholding.

MR. SHANKER: You've got to be very careful. Even though it sounded like New York and PJM were the same in some sense on this, they're not at the detail level.

As Joe said, the ICAP obligation is both an obligation to bid into the day ahead markets and an emergency call.

In New York the obligation is to offer into the day ahead market but actually the emergency call may not transpire into real time because of fuel considerations. We've seen recently people are releasing fuel into the real time having met their obligations to offer into the day ahead markets and it gets even more complicated in that you sometimes have, although I misread a contract the other day, I thought someone had a very good motivation to withhold in the day ahead market because the product was hedged and offered in real time.

A reasonable evaluation would say that wasn't physical withholding and it wasn't anti-competitive.

So the bottom line is, you need to do what David said which is you've got to see if somebody is withholding in the context to exercize market power and the mandatory offer may be a good summary statistic but it's not really what you want to be focusing on. You want to focus on the mechanism that may be getting an unreasonable profit in that.

MR. MEAD: The ICAP obligation that Joe and Roy talked about is in a certain sense something that a generator voluntarily agreed to take on -- what about for generators that don't take on that obligation voluntarily or in markets that don't have ICAP obligations, do we need to worry about "must offer" in that context?

PA: They did voluntarily take something on. They came and asked you for market based pricing. The fact that they're not being paid for capacity for reliability purposes doesn't give them a free pass to exercise market power -- the quid pro quo they got market based pricing.

That is a confusion then that has percolated through New York for a very long time because there's a requirement to bid in the day ahead market for capacity sellers.

Capacity resources -- in fact I think Roy asked me early on why should non capacity resources be subject to market power mitigation? The answer is, because it clearly has nothing to do with whether you sold capacity or not.

MR. SHANKER: I think that's where the distinction comes. In these markets there's a contractual obligation through the ICAP mechanism -- where someone isn't involved in that market mechanism there is no obligation to offer but there isn't a free pass to exercise of market power. That's a significant distinction. Nobody's going to go around saying it's okay to exercise market power.

The issue is though it's also okay to discretionally operate in facilities as long as you are not exercising market power.

MR. THILLY: It's so difficult to distinguish between scarcity and withholding. It may be that it's possible but it's very difficult. I think that's true. Having a resource adequacy requirement that covers fixed costs allows you to have a "must offer" requirement because the capacity cost has been covered. That makes it a much simpler way to deal and a much safer way for the customer.

You also have to recognize by the fixed costs covered through retail regulation in many cases they are or through long term bilateral wholesale contracts -- if that's the case there's no reason why in a competitive market that energy would be bid at marginal plus some profit -- that's what would happen because they would be making money.

We've got to take account again of the facts and try to set it up as simply as possible with as little gaming opportunity as possible.

MR. PERLMAN: Can I ask a question about that real quick? It follows up on something Roy said earlier.

The scarcity pricing you all are talking about is I assume the type that has really real clear cut sort of break points when you reach a period of scarcity when the operating reserves have been affected.

In all other circumstances, am I correct that you would have no scarcity pricing that would happen? Sort of volitionally by the market participants?

It would all be subject to the same sort of mitigation that you have all the other times, so it's really an administrative break point and I understand those things are necessary and shouldn't be sort of denigrated as David Patton said earlier -- but they're a judgmental set of rules.

I just want to make sure we're all talking in the same place where you start scarcity and where the price goes. Is it an administratively established process that has some basis in maybe the operating reserves in the market or some base in some structure but is not going to happen sort of on its own? Did i get that right?

MR. SHANKER: Yes. That's a reasonable summary.

MR. KLEIN: Let me just add to that that it's important that what's defined as "scarcity" includes all the different things that the ISOs do potentially or LSE do when things get tight. There ought to be some mechanisms if they have an operating procedure that says "okay I'm going to violate certain transmission constraints." If that results in prices collapsing then we don't have good scarcity pricing.

If demand side resources get picked up, 1,000 megawatts get picked up and they go in as zero offer units, then the price is only $50 because we don't have an operating reserve problem.

That's not good scarcity pricing. So it's a much more complicated thing. We'll see how New York does this summer but I suspect there's going to be tricky little details in not out of an intention to harm the market and scarcity pricing but that it will be very hard to capture all the different things that the operators do in real time to make sure load is served. That really should look like scarcity.

MR. PERLMAN: The reason I'm asking from a regulatory perspective and I'm an economist not a lawyer so it says here from what I can tell half the economists will say it's scarcity pricing. The other half will say it's the exercise of market power and it's the same thing.

I know there's debate about that.

MR. O'NEILL: Speak for yourself, Dave.

(Laughter.)

MR. PERLMAN: Dick is very clear and in helping us do what we're doing in order to have a better approach to mitigation and scarcity pricing and have it embedded in the regulatory regime it would seem to me for us to do this we need to be very clear and to say "in this set of activities you're going to be subject to mitigation or to these circumstances." End of story.

And when these circumstances occur, as Roy said before, "scarcity pricing will kick in" and it doesn't really matter what you do because the price is going to be what the price is going to be and then we would have a whole lot less ambiguity into how to implement rules and maybe a little more clarity on how to do mitigation and address local market power because we've sort of taken that out of the hands of the market participants and put it in the hands of the structure.

MR. PERLMAN: I agree with you. What most economists would agree on is, if you can't point to anyone withholding any resources -- in other words, you're fully utilizing your resources and you still can't meet your operating reserve requirements or whatever, clearly you're in shortage.

I think designing the mitigation, that's the premise in the conduct and impact tests that are used to trigger mitigation in New York, the conduct tests are intended to detect when there is withholding.

If you're not detecting any withholding and you're short of operating reserves, you can have confidence in the scarcity pricing signal. It's the reason why it's important to have relatively transparent thresholds and understandable rules about when you exceed those thresholds.

MR. SHANKER: It's worth clarifying the point that Abram brought up -- there's two different things going on. When we say it's sort of automatic that's correct but there are situations where the operating rules change and so what you price to may be inconsistent with the reality of the operation.

The best example is in New York. There was a fire at a substation and several cables were lost. The operators legitimately said "time to be super conservative" and they turned on everything at minimum.

Basically they're operating to a third or fourth order contingency. Had you priced in the LMP algorithm to that, prices would have gone up if you'd shown the contingencies, the third and fourth order contingencies -- what happened was people had all those units running at minimum and then priced against the first contingency.

Under normal dispatch rules the prices went down.

I think we reached agreement that's never going to happen again. You can ask David.

(Laughter.)

MR. SHANKER: The point is that there are a lot of details in this and we've had similar things in PJM -- PJM operators have gotten very conservatives at times of peak and did not cycle some of the combustion turbines.

They kept them on. They were afraid they wouldn't restart so we had some excess generation that was suppressing price.

It was an absolutely legitimate operating decision. There was no reason to question it but we have to think about what things like that do to pricing because you're suddenly saying the system as a whole is a little more edgy. Maybe I should have a more conservative operating profile and that has to set a different background for how we price in the market mechanism.

MR. O'NEILL: What you're saying, Roy, is that the operators decided to bring on more reserves but it wasn't priced properly?

MR. SHANKER: Exactly. There's nothing wrong with that -- when they explained why they did it it made perfect sense.

MR. BOWRING: We've talked about how automatic it might be to define what scarcity is but defining what the price is during different levels of scarcity is not automatic and if somebody has to say what the price is and it's not coming out of the market someone has to say what it is. That again has to be a rule and that's I think -- that fact is a reason to think very seriously about whether we want to go down that route.

MR. KLEIN: I think that, if you look at where we are on that spectrum, are we too far over in terms of too high scarcity pricing given the bid caps or too low scarcity pricing? I think it's pretty clear from the evidence of market performance, when we did have tight markets that, if anything were on the wrong side of that one and it should be higher revenue than lower.

MR. BOWRING: You are talking about aggregate. The aggregate issue, which I identified also and I think it's important not to confuse the fact that aggregate revenues are low for whatever reason, whether it's your market design issue or something else, or competition -- aggregate market revenues are low.

Let's not confuse that with the local market power issue. That doesn't mean that doesn't have any necessary implication with anything having to do with local market power. It does mean that we do get wrong in local market power.

In fact, the evidence is that we're not. The net revenues of those being cost capped are about the same as those not being cost capped.

MR. GRAMLICH: Just to clarify this question that seems unresolved, there's an open question about how much scarcity pricing and when. Roy doesn't want to pay infinite. He doesn't want to pay $5,000 a megawatt hour every hour for the next three years before there's a transmission line.

On the other hand, I think you acknowledge, Roy, that there is some capacity value that would not be reflected in a market price that cleared at somebody's short-run, least-efficient units' short run marginal costs for this intervening period.

So we have to figure out how much scarcity pricing and when.

MR. PERLMAN: Stated another way it seems to me what Joe was saying and I think Dave's agreeing is, it's just a policy question. If the Commission were to involve itself in saying when scarcity is and then help incentive establishing or in the pricing, which is an administrative structure in that arena and then having sort of amp the rest of the time, which is sort of the New York model, no one would accuse us of interfering with markets with that.

MR. BOWRING: It sure sounds like Bill's slippery slope to me, but what do I know?

MR. HOGAN: I would make a distinction for your purposes of clarity. I think what you need is clarity and when market power and mitigation apply so you should have some ex ante rules. I think you can make that pretty transparent -- not completely but pretty good.

I don't agree that scarcity is a binary thing. I think it's a relative thing. That means there's always a mixture of both things going on and I think Joe Bowring is exactly right. I didn't understand what he was saying initially but I think now I agree with him when he points out, "well, the demand curve for operating reserves is an administratively set demand curve." Right, that's a fact.

And that's life. The demand curve for ICAP is administratively set. Not only that, it's an administrative product. It doesn't actually even exist.

Operating reserves are different. You can actually go out and test and measure and so forth and things like that are dictated by the technology because you don't have the response time.

If we had better response times then we wouldn't need it and I'd be making a different argument. That's a fact that you have to have an administrative demand curve and you do whether they're vertical or sloped.

If they're vertical then you get all kinds of bad incentives, so clarity there is bad.

What you really want is sloped, then there will be a mixture. That's the buying side. Now on the supplying side that's more like a market and it may have market power. Therefore you have to mitigate the market power on occasion and you can have some rough rules about when you do that to provide some clarity.

I think that's the reality so, if there is no pure market solution given the technology, particularly in terms of operating reserves and you just have to -- that becomes the responsibility of the regulator and the ISO advising and NERC conversations about what the standards ought to be and where we set these demand curves and what they ought to look like.

The same with the damage control bid cap -- $10,000 would be better.

MR. COLEMAN: Do you even need that damage control bid cap if you have amp -- can you get rid of the damage control bid cap?

MR. PERLMAN: You need to reserve demand curves. The important thing to recognize, though, is that you've made a lot of these decisions. You just don't know it yet.

(Laughter.)

MR. PERLMAN: We thrash it out and say how much a reserve is worth. If we're going to set a demand curve at what level should we set it? You've already set it because you tell the operators every day, day in and day out, "I want you to accept energy up to $1,000 to back down a steam unit that partly costs $50 or $70 to create reserves if you're going to be short of reserves. The shadow price for reserves is $900 or $950 so you already told the ISO "pay $950, don't pay anything higher. There's an implicit value.

What gets lost is that,when that option isn't available or when it's happening out of time in sequence, like we have to accept out imports on an hourly basis but we set prices on a five minute basis, there's no way of reflecting that $950 shadow cost in the energy price.

What happens in most of these markets is, the operators press the magic red button and release the reserves into the market.

If you had told them they should be paying $950 to maintain the reserves they've just injected a $950 resource into the market in order to keep the lights on -- in other words, lowering their operating reserve holdings. That doesn't translate into energy prices anywhere and that's the whole crux of the scarcity pricing.

The important thing is that all your decisions be logically consistent with one another. If you decide reserves aren't worth $950 you need to rethink the safety net bid cap in making sure everything is working together in a consistent manner.

MR. COLEMAN: Thank you.

Since we've gotten back on time, with time management, I want to thank everyone for a very lively and useful discussion. We will break now until one-thirty.

(Whereupon a luncheon recess was taken at 12:10 p.m.)

A F T E R N O O N   S E S S I O N

1;35 p.m.

MR. COLEMAN: If you'll take your seats, we're going to get started here.

This afternoon we have two panels, the first panel is going to be focusing with a little more granularity than I think this morning on some of the RMR experiences in the Northeast.

One housekeeping matter before I turn it over to the speakers -- a number of speakers have been working from presentations this morning and brought copies and some have been distributed.

We'll be sending out a follow up e-mail to all of you asking you to send us an electronic copy of your comments so we can post them on our website under the technical conference so that we will be certain that everyone will have an opportunity to view what you have to say.

This afternoon's format, we're asking speakers to try to limit their comments to five minutes. We will follow the same format as this morning with a Q&A session from Staff and the Commissioners.

Our first speaker this afternoon is John Anderson, Managing Director and Head of Power and Project Finance at John Hancock Financial Services.

Welcome, John.

MR. ANDERSON: Thank you, Mr. Coleman.

I'll really focus my comments as an introduction on who John Hancock is and our investments in the power sector. I think you'll find that we're very representative of a large base of investors that some of the speakers spoke to this morning.

Hopefully I can amplify that in a first person kind of way as one participant in the debt market for power. By way of introduction, our perspective at Hancock is unusual in that we have a large and very diverse investment portfolio in the power sector. I manage an investment team at Hancock with an $8.5 billion portfolio in power.

One of the things that is noteworthy about our portfolio is that we're spread across a wide range of sectors in the industry. We have a large portfolio of loans to regulated utilities directly. We also have investments in utility holding companies but also most of our investments are on the unregulated side.

So if you looked at my portfolio, the largest single area of my investment has been in independent power projects where we've invested in companies that are essentially taking the risk that they can perform to a long term contract to a regulated load serving entity. That's been a very opportune and good fit area of investing for us.

The reason that we like the power industry and that asset space is that, generally speaking, on the regulated side, it's been nice and stable and we've had good performance from our portfolio and one of the reasons that life insurance companies like the power industry is that the assets have very long lives and, if we're rating 30 year life insurance policies on one side of our business, we want to find an industry that we can invest into that can provide stable returns over a similar life and power assets have a lot of those features.

In many ways we feel that we're a natural ultimate investor for power generation assets and power infrastructure. Many of the comments that you heard this morning I think echo that. Not surprisingly I think it is an important source of capital.

Most capital for power infrastructure is provided by debt markets not equity markets. If you look at capitalization of power assets, as you probably heard this morning, we value stability. We're not in this to make a killing off of spiking peak power prices. We're putting capital into this business in opportunities that we think can provide long term stable reasonable returns and are on the low end of the risk adjusted spectrum.

With that as an introduction I am happy to provide any comment on further topics of interest but I thought that would be a good way to start off, just to introduce the perspective we bring.

MR. COLEMAN: Thanks, John.

We're going to move to another member from the financial community, actually someone who was on our first panel, but we'll give Jonathan Baliff an opportunity to provide some additional comment on behalf of CSFD.

Jonathan?

MR. BALIFF: Thank you again. What I wanted to get into at least in the afternoon is a little bit deeper examination of just really how do you finance a specific generation project or a specific project to alleviate some of the load or RMR concerns that Credit-Suisse First Boston is the financial advisor.

One is SES, that is, the name of the developer, Astoria. SES Astoria is a 500 megawatt gas-fire combined cycle plant in the Astoria load pocket very close to LaGuardia Airport. If you ever come out of LaGuardia and go towards the City you'll basically pass this facility. It is on a 23 acre site very close to a substation.

The second project that we'll get into which was mentioned by Abram -- basically that's a 1,000 megawatt BC intertie between Upstate New York and is in the middle of financing.

Both these projects right now are in the middle of what we call the "financial sales process." We are going out to investors to basically sell the debt for these projects. They are right now being sold as, not corporate projects, but as asset projects.

What do I mean by that? The debt investors will get security. They will own the asset.

In the down side scenario, if the privates don't perform, they will take the asset themselves and try to do something with it. That's what's called a "secured asset."

Both of them are going to be financed in that way so that we're not looking for any corporate parent to be able to provide any guarantees.

Let's go to SES Astoria. The primary way we sold this asset is that it has a first mover advantage. That is the most important way to sell an RMR or load pocket project and it's obvious it can't take so many projects. You only need one or two at the most, maybe even just one.

There's a debate obviously with some of the gentlemen who were here before on how the actual market is going to work. The financial guys just want to know are there going to be sustainable cash flows here, the way we sold and the way we are selling SES is, "yes."

There is a first mover advantage. This will be in the Astoria load pocket. It will crowd out virtually any other significant project in that area and also affect the ability for anybody else to come in and steal the economic lights.

Although that sounds a little bit pejorative, we're a bank. We're trying to sell our client to these investors. One of the other ways that we sell it, as I said very briefly, there are five risks that all the investors look at in these types of projects -- construction risk, market risk, operational risk, fuel risk and regulatory-political risk.

You must have answers to all five of those questions. If you're going to face somebody like John Anderson who, I can tell you, will grill you for at least an hour and then you can have conference calls with him throughout the sales process on and on.

This is a big amount of money that these guys are going to be putting to work.

Let me talk about market risk. The debt investors will not take market risk right now. THey'll take a little bit of market risk but they're not going to primarily take most of the market risk and what do I mean by that?

In the first five to 10 years, it's debt. Better amortize -- i.e., book most of the debt better be paid off before in a load pocket entity before a debt investor will take any money and put it in.

So we need to have a contract. That was almost a necessary but not a sufficient condition to get this financed and you need to have a credit-worthy off take.

What we mean by that is an investment grade triple B minus or above -- and I would say, today -- and correct me if I'm wrong -- you probably want higher than that?

MR. ANDERSON: Right.

MR. BALIFF: We want to see somebody like a Con Ed, who is an A rated entity come in and give us a nice 10 year contract. I'm not going to get into the details of what that contract is but, for the most part, it needs to create a stable cash flow stream.

I'm not going to get into operational risk because most everybody knows these CCs or the combined cycles are normally very standardized technology like G-E Frame 7s, very easy to operate. Fuel and operability must be done under not as long a contract, but it can be done under a shorter contract. But it must be handled.

Finally, the regulatory and political risk combined with the construction risk are not mutually exclusive, especially in load pockets.

What we are selling the investors is, from a political standpoint, the project has tremendous political advantages with both the city councils, both the borough presidents and we're looking at investors who might even go talk to the Borough President of Queens to understand what this project means to them.

Why? Because construction costs are mostly time sensitive. What do I mean by that? We set down a pro forma projection based on the time it would take to construct given the nature of trade costs in New York City. Time not only is money -- time is blood, sweat -- it's everything if this thing starts getting delayed.

We consider a project to go approximately $1.0 million per month on just construction and labor alone. That is a very big part of what we need to get settled out. We expect that SES will be financed in the next two weeks. We've pretty much got the debt financing lined up with institutional investors that I talked about this morning. The equity is going to be provided by very nonstandard equity providers.

What do I mean by that? No strategic equity. It's going to be provided by private equity and some of the same people who are in the debt are going to provide the equity in the project itself, so I take questions on SES and Astoria -- and also conjunction since my time is short -- but conjunction is being financed in a very similar way.

Thank you.

MR. COLEMAN: Thanks, Jonathan.

Next, we have Mark Reeder from the New York Public Service Commission. Welcome, Mark.

MR. REEDER: Thank you very much for giving me the opportunity to share my thoughts here today.

The qualifier is, these are my thoughts and not those of the New York Public Service Commission. I was asked to focus my comments on the capacity market demand curve. There's a fair amount of discussion of it this morning. I'm just going to try to gather together int he short amount of time I have.

(Slide.)

I did bring copies of an affidavit that Dr. Thomas Painter of our staff filed with FERC in April which explained the whole thing. It was designed to be self-contained. If anyone didn't get a copy of that, that would help. I can't cover it all in five minutes but I'll just go through the highlights.

The motivation for the demand curve came out of two pretty big problems that we had with the capacity markets. The first one is that they had this boom and bust cycle. The parties called it "falling off the cliff."

If you got a little bit extra the price would just crash. Because the purpose of the demand curve -- I'm sorry, because the purpose of the ICAP market was to provide this extra revenue stream to help get entry and then we talk to bankers and we see people saying "the revenue stream is discounted to next to nothing because of how volatile it is -- it seems to be dysfunctional, so the demand curve is priced to smooth out that revenue stream over time to keep the lows from being as low -- keep the highs from being as high.

The second big problem is, we felt there was a very strong volatility to market power in the capacity market. With a little bit of excess withholding could drive you to a shortage and send the price through the roof and we did experience that once in New York and it wasn't a pleasant experience.

So if you could flatten it out with the demand curve you could make the revenues more stable over time from the perspective of the generation developers and protect against market power from the perspective of the consumers, so that's really where it came from.

It had one additional feature that was nice and that is, we felt pretty strongly that, if you had 118 percent reserve requirement, that 119th percent isn't completely worthless from a reliability standpoint. Having a little more is okay and it does help reliability.

So it didn't make sense for the system to have a willingness to pay -- this is this vertical demand curve, I think, as Mr. Gramlich mentioned, that says "we'll pay absolutely everything up to 118 and absolutely nothing from 119.

It didn't seem that the system should express that willingness to pay so we put in a demand curve, look at the graph that's on the screen -- and that graph, 118 percent, is the point that denotes the required reserve margin. That's the one that equates to one day in 10 years' reliability.

There used to be a vertical demand curve right at this point. Like a demand curve does, it just puts a sloped curve through that same place and one of the keys is, you have to decide how high to make it. If I have time I'll get to that later.

But what you can see here is, at the 118 percent point the price here is $56 per kilowatt year, a little bit more, say 120 percent -- price doesn't crash, it drops down the curve to $48.

What that does is produce much more stable revenue streams in times of moderate amounts of surplus. It avoids the crashes and also, as was mentioned earlier today, if someone withholds to drive you from 120 percent back to 117, instead of going way up to a deficiency charge that's quite punitive, you just slide along the curve there also.

That removes the extent to which price jumps in response to withholding. That merely knocks a hole in the profitability of the economics of a player considering withholding. It takes the incentive to withhold away or greatly reduces it.

So that's the basic reason we proposed it and the parties basically went for it because it seems to accomplish those goals and those are real important goals.

There's a third goal that wasn't really mentioned earlier today and that is that the curve has to be steep enough so that, if you offer this extra money and you get tons of capacity, you don't end up just having way too many.

If you get quite a bit too many the curve drops down and the price drops to choke off the problem of excess supply. Determining the height of the curve, I'll just have a brief amount of time. This is a key parameter. People talked about this as an administratively determinate thing and it is -- at the 118 percent point the height of the curve should be an amount, or it starts off at the amount that a generator needs to cover its capital costs after considering the fact that it gets revenues from the energy and ancillary service markets.

So it's the net revenues. It still needs on top of what it gets from the energy ancillary service markets and what we thought was important to do, is to decide what that number is but set the curve higher than that to err on the side of reliability, if you will.

For example, if you thought it was $50 on this graph that we were looking at and it turns out so you set at, say, $56, if it turns out the cost of entry is only $48, entrants may come in so long as they can get more than 48 and drive you to the right along the curve to point B on the graph and you may settle out at a price of $48, so that the mistake of setting it too high is, you end up getting a little too much. You might get 120 percent instead of 118 percent and pay $48.

So it seems to make sense to err on that side.

So just to summarize, from a consumer point of view, it is very valuable. It protects against the market power but it also takes this big chunk of money you're going to give out over 20 years in the capacity market and provides it in a more stable way so you buy more entry for the same amount of money over time.

So in the question and answer period we can discuss some more pieces of it because there are a lot of other pieces of it. But basically I think that's really what there is to it.

Thank you.

MR. COLEMAN: Thanks, Mark. Certainly we'll get into a few more questions on that in the Q&A.

Next we have Steve Wemple from Con Edison.

MR. WEMPLE: Thank you, Michael.

Good afternoon, Chairman Wood, Commissioner Brownell, Staff -- my name is Stephen Wemple, Director of Retail and Regulatory Affairs for Con Edison Energy, which is a subsidiary of Con Edison, Inc.

I am appearing to day before the Federal Energy Regulatory Commission on behalf of the Edison Electric Institute and it's affiliated Alliance of Energy Suppliers, a division of the EEI that specifically represents power suppliers and also on behalf of Con Edison Energy.

Con Edison Energy and its affiliates, Con Edison Solutions and Con Edison Development, are active in the New York, New England and PJM energy markets and own over 1,500 megawatts of generation and supply approximately 1,500 megawatts of retail load in New York, New Jersey and Massachusetts.

First I would like to commend the Commission for accepting the recommendations of EEI, PJM and others to convene this technical conference. The first part of my remarks address EEI's position on this topic, with which Con Ed Energy fully agrees.

Before concluding I will also share Con Ed Energy's perspective based on our own experiences owning and operating peaking units and hedging retail load in the Northeast.

EEI believes that generators must be adequately compensated when required to provide the reliability services necessary to support the electric system. In fact, the Commission has an obligation to adopt rates that are just and reasonable for consumers and generators.

Consistent underrecovery of investment dollars which has been occurring in the New England and PJM markets will naturally lead to reliability problems as owners are forced to defer maintenance on or retire existing generating units.

The problems EEI is concerned with is the need for a reliability "must run" contract is indicative of a failure in the design of the local markets to provide adequate compensation for units needed for reliability.

If the existing market rules are not providing adequate compensation the ISO or RTO should determine that the need for design changes that can provide adequate compensation and work with stakeholders to effectuate the necessary changes.

EEI's preference is for a market based solution to determine appropriate compensation in the absence of market solutions. EEI believes that out of market intervention is appropriate to ensure reliability and that such intervention must be structured to provide adequate compensation to the extent possible to emulate a competitive market based solution.

Because many of the units considered for RMR treatment are located in areas where there is limited transmission and/or generating capacity there are concerns that such units could exert market power absent some form of negation in situations where there is a demonstrated concern about market power.

Monitoring mitigation or other measures may need to be considered to restrain the exercise of market power. In such instances, the RTO ISO needs to establish and publish a clear objective standard on what constitutes market power and the criteria for imposing mitigation.

However, mitigation measures have to be structured in such a way that they do not discourage the long term investment signals and must not deprive existing owners of the opportunity to recover all long-run marginal costs including variable and fixed costs.

For example, mitigation units' bids to variable production costs will deny that unit any opportunity to recover fixed costs from the energy market.

In addition, if a region does not have sufficient supplies to meet its load and reserve requirements, then market rules and mitigation measures in particular should not set prices artificially low and suppress the natural price signal that supplies are scare.

Ultimately EEI believes that a market that is able to attract and retain necessary resources, local or delivered generation and demand response without the use of subsidies is in the consumer's best interest because it provides a long-term solution to relieve market power concerns, maintains reliability, produces just and reasonable rates and enhances quality of service.

The design of RMR and mitigation measures needs to offer variation, including regional ones, due to differences in resource mixed cost structures and operating requirements. The costs associated with RMR mechanisms should be borne locally and preferably conveyed through well designed existing mechanisms such as capacity and/or energy market pricing.

This allows loads to either react to the price in the local reliability need with demand response measures and/or be able to hedge their costs through purchases of capacity and energy.

With respect to capacity markets, EEI believes that a variety of mechanisms will allow RMR generation to obtain adequate compensation. For example, properly structured regional capacity markets with deliverability requirements and properly structured locational capacity markets.

Finally EEI believes the market monitor needs to be truly independent of the markets they monitor and have a screening but not determinative role in establishing the need for mitigating RMR units. The ISO RTO is not -- the market monitor should decide how to implement RMR mitigation. EEI believes mitigation rules and implementation procedures need to be clearly articulated in tariffs filed with and approved and accepted at the Commission.

I'd now like to take a moment to share Con Ed Energy's experiences as the owner of peaking units in New England and PJM. Con Ed Energy --

MR. COLEMAN: Make it brief, Steve.

MR. WEMPLE: Very brief, Michael.

Con Ed Energy believes that the problems facing RMR units are symptomatic of issues facing the overall energy markets, in particular, PJM and New England. Last summer I performed an analysis of prior PJM state of the market reports, presented the results to PJM and included them in our October 30th comments on the proposed PJM mitigation plan.

My analysis indicates that the net revenues for peaking units were overstated in each of these reports since 1999, which makes the revenue shortfall worse than has been reported. From 1999 through 2002, peaking units have only recovered 70 percent of their required revenues.

Last year was even worse and the forward curves indicate that 2004 and 2005 will only provide 30 percent of the requirements. This means that existing units may not be able to afford normal maintenance and no new merchant plants will be built without significant market reforms.

PJM and the other regions need to focus on solutions to these problems and solutions include compensating units that provide 10 minute non spin and 30 minute reserves and if there are local requirements, local markets for those services, too -- establishing scarcity pricing rules so that when on short on energy and reserves or using block loaded units or making emergency purchases, energy prices are not set artificially low by on-line units and reform the capacity markets to value resources in excess of minimal requirements as we've heard other speakers say and, from an LSE's perspective, RMR funding mechanisms should work through existing capacity and energy markets where practical to avoid unhedgeable costs.

Out of market payments for RMR units that create unpredictable uplift costs are harmful to retail markets as they create uncontrollable financial risks for LSEs.

Thank you.

MR. COLEMAN: Thank you, Steve.

Next we have Richard Rapp from KeySpan Energy.

Richard?

MR. RAPP: Good afternoon. Thank you for

inviting KeySpan to participate in today's conference. I'm here on behalf of KeySpan Ravenswood, which owns and operates approximately 2,200 megawatts of generating capacity in New York City -- the "New York City" often referred to as "Zone J."

In addition we are in the final stages of completing the 250 megawatt combined cycle unit which should be on line in the next several weeks.

Energy resources including generation, transmission and demand response require just and reasonable compensation if they're going to provide the services required to meet the needs of customers in bid-based markets.

Moreover the needs of customers should be established using mandatory reliability requirements. Otherwise, investors will be unaware of the potential necessary infrastructure enhancements. Once mandatory reliability requirements are established, a market design that provides an efficient price signal for investment to meet these reliability requirements is required.

In a bid-based market that price signals should be as uniform as possible to all market participants -- in other words, the same price signals should be provided to all providers providing the same service. If the market is designed properly it should provide sustainable price signals that will encourage the investments required to meet reliability requirements and RMR contracts should not be required.

Such a market design would include a stable capacity market including locational requirements as necessary locational based marginal priced energy and ancillary services such as operating reserves.

Opportunities for the participation of demand response and appropriate scarcity pricing mechanisms are also an important aspect of an efficient and successful market design.

KeySpan recognizes that, even with such a market design, there are concerns about potential local market power and reasonable rules and regulations such as mitigation measures may be required in certain markets to protect against the potential abuse of market power during the continuing evolution of competitive markets.

However overly intrusive and excessive mitigation can result in the distortion of price signals that the market requires to ensure new and existing resources are available for reliability.

In addition, mitigation measures should be balanced and applied uniformly to all market participants including purchasers. It is not only suppliers that may have potential market powers. Purchasers that have monopsony power can distort markets and abuse market power as well and can cause prices to be depressed from otherwise competitive levels if markets are not designed appropriately. Bid-based market designs must therefor account for and anticipate both possibilities.

Local market power is difficult to define precisely. In general, KeySpan uses market power as the ability to increase or decrease market prices from competitive levels in a predictable and sustainable manner.

In a properly designed based market local market power should not be a concern and targeted mitigation measures can effectively prevent potential abuse.

For example, unit specific bid caps based on costs can prevent individuals from increasing market clearing prices, locational based marginal prices assure all resources are paid the same competitive price.

We share the view that RMR contracts are the result of market failure and should only be utilized as a last resort. RMR contracts can further distort market price signals unless the market design is revised such that the RMR contract is somehow reflected in market prices.

Buyers and sellers need to see an efficient price signal to prevent further market distortions. RMR contracts or other out of merit resources should be permitted to set clearing prices in appropriate circumstances such as when markets are short capacity or operating reserves.

It is important that market prices reflect RMR contract costs in these situations notwithstanding potential market power concerns. Otherwise the need for RMR contracts would be perpetuated and reliability could be jeopardized because new resources will not have an efficient price signal in which to respond.

Additional infrastructure should not be forced on the market to mitigate potential market power concerns, eliminate load pockets or mitigate prices. If efficient economic signals exist, which are the result of achieving mandatory reliability requirements, investments in generation transmission or demand response will be made where appropriate.

Cross based regulated infrastructure intended to eliminate congestion, mitigate purported market power or resolve load pockets should not be made in a competitively based market.

Cost based regulated infrastructure intended to eliminate congestion may in fact not eliminate it. It might merely impose the additional cost of the regulated infrastructure on consumers. If congestion costs in fact do not go down as the result of the regulated infrastructure consumers are then faced with paying for the regulated infrastructure in addition to the congestion costs. In some instances it could very well be the congestion costs represent the least cost solution for customers.

Addressing quickly spot market price mitigation, in general KeySpan does not think spot market energy price mitigation is efficient or necessary. ISOs can keep up with changes that occur on an hourly basis in real time markets with respect to fuel costs, opportunity costs, risk and other real time events.

Gas market real time prices are not mitigated and they have a significant impact on real time energy cost. The real time energy market is essentially a balancing market that should not be mitigated.

The volumes transacted, the quantity of supply and the inability to predict real time markets argue against mitigation.

I also have some prepared remarks that I have put in written form. As well, as I was going to address some regional issues related specifically to the New York ISO. I'll save that for the discussion portion.

Thank you.

MR. COLEMAN: I appreciate that, Richard.

Next we have Jonathan Falk from NERA.

MR. FALK: I want to thank the Commission for the opportunity to share my views on when and how the RTOs should deal with local market power concerns.

First however let me say my presentation is being sponsored by the marketing and generation organizations of PPL Corporation. PPL is a member of PJM and one of its original founders. It operates several generating units in PJM which have been subject to offer capping and one in New England, the Wallingford facility, with which I suspect the Commission is somewhat familiar. PPL also owns and operates generation in Maine, New York, Montana, and Arizona and distributes electricity to 1.3 million customers in central-eastern Pennsylvania.

I want to focus my remarks today on the first question FERC posed in its cyclical conference agenda. What is local market power? Why should it be mitigated?

I have come to the conclusion that a lot of the controversy that this question has caused is a direct result of not really thinking about this question in the appropriate context.

The insight I have had and I hope you will agree that it's a useful insight, is that local market power is simply the ability to collect a locational rent, that is, it's an opportunity for economic profit that flows from the fact that certain units at certain times are much more valuable than other units.

The value stems from the fact that, without them, the reliability of services is threatened and reliability is very, very valuable. There is no other rent that we don't allow generators to try to capture. If they can generate very cheap power we let them capture the difference between their costs and the market price.

If they have savvy trading operations we let them earn as much profit as they can on that operation. If they've signed contracts that turned out to be priced above market price over time we let them keep those profits.

Why do we even call these locational rents "market power?" I think the reason is that we've been too focused on the technical definition of market power as the ability to affect price. This definition is not helpful as a practical guide in two respects.

First, to be accurate, it has to be conjoined with the notion of sustainability. That is, market power is an ability to significantly affect prices which cannot be thwarted by entry or by actions of other current market participants.

We focus on affecting price but we tend to wave our hands when considering the effect of entry on the sustainability on the price increase except we sometimes assert that entry would take "too long," whatever that means.

The second reason which -- the first I think we've talked about before. The second reason is even more pervasive. We don't really ask what it means that the unit in question can affect price. The only reason that it can affect price is that it's output is more valuable than another unit's output to fulfill the local reliability function.

This is a good thing and it ought to be encouraged with at least some level of rents to induce others to enter in an attempt to capture those rents.

Why do some think that locational rents are different from the rents that come form fuel cost differences, favorable rent times or any other host of things which make some generators perform better than others. I think there are three main reasons.

One, the rents which are earned from location aren't really earned. They represent historical accident and thus would just be a windfall to the person who happens to own the unit.

Two, load pockets aren't readily susceptible to new entry, or, three, the loads inside the load pockets are captive customers who deserve protection.

None of these reasons, however, are without weaknesses which, when carefully considered, undermine their superficial appeal considerably.

First, even if the initial distribution of these rents may be accidental -- and for recently constructed generators in expensive load pockets like PPL Wallingford, they shouldn't be considered accidental -- the whole point of generation competition is to generate better patterns in the future. Leaving some level of rents out there for generators to potentially capture is the price we pay for dynamic efficiency, just as all the other rents which a generator can earn from, say, a reduction in its heat rate promotes that sort of innovation.

Second, while there may be some load pockets for the barriers to go into that really are structural. This is the point a lot of people made this morning. We know very little about what changes the transmission infrastructure or what entry decision could completely eliminate the incumbent generator's locational rent.

The New England Committee experiment, which I assume we'll discuss a little more, is quite instructive in this regard. They're not as reliable. As a matter of fact, competitive systems are very good at arbitrating rents. We ought to give them at least an opportunity to try.

Third, as to the protection of captive customers, if the barriers really are structural, and if competition can really solve these problems, the customer should need no more than temporary protection and to achieve the dynamic effects we have to loosen the constraints on price. The line between gouging and incentives is one regulators will have to draw but it makes no more sense for customers to keep these rents than generators. And if we use the analogy of market power to try and cap these prices at short run variable costs we shouldn't fool ourselves into thinking that we're doing anything other than allowing loads to capture these rents by allocating these rents to consumers at the expense of generators. We not only give no incentive for anyone to relieve the constraint, through new investment or load response, we actually give consumers incentives to locate within the load pockets and make their problems worse.

The upshot is the operation of the electric system is producing locational rents whether regulators have realized it before or not. They're going to have to decide how to allocate the locational rents. That's a simple fact. Giving some of those rents to generators, i.e., allowing them to use some of their so-called "market power" is the only way to keep these temporary problems from becoming permanent.

As a final point, if we decide for whatever reason that a load pocket is chronically in need in mitigation, and, of course, there could be some, we would be better served finding a market mechanism to replace indefinite administrative oversight and the reposed PPL auction mechanism. PJM provides that necessary fall back mechanism in those remaining situations that markets can't correct.

I'd like to thank the commissioners, commission staff and those of you in the audience. I'll answer any questions that I have. Both this and the long version of that are available for anyone who wants to read it.

MR. COLEMAN: Thank you for being brief. Next we have Steve Corneli of NRG Power Marketing.

MR. CORNELI: Thank you, Michael. Thank you to the Commission for having us here today to address these really important issues of RMR conditions, compensation and the relationship to market power.

NRG owns significant amounts of competitive generation in the constrained areas of PJM, New York and NEPOOL. I guess you could say we're intimately familiar with mitigation, RMR issues and related market design needs. We really appreciate this opportunity to talk to you about those issues.

As I've listened today, I think I've discerned that the real theme of this technical conference is maybe what is the critical policy issue facing these areas and it seems to me that what a lot of people are saying is that the critical policy issue is not the mitigation of market power and trying to keep prices from being too high. It's the mitigation of market design flaws that are keeping prices too low.

I want to talk about four points, I think, that address the topics for this panel and that reflect some things that other folks have said today that illustrate those needs and the potential solutions.

The first point, there is really good evidence that the exercise of market power is not taking place in any of these three markets in the Northeast. That's good news.

It does suggest that we need to focus not so much on the exercise of market power as something else. The definition of market power as other panels have said is when sellers have the ability to raise and profitably sustain prices above the competitive level. I submit to you that there is no better indication of the competitive level in area that needs new resources than the long run marginal cost of investment in that region.

Each of the three market monitors for each three northeastern market areas annually puts forth a state-of-the-market report that shows and has consistently shown that in new place can new entrance recover more than their long-run marginal costs. Indeed, in most of the constrained areas, they recover considerably less in the market. That means there is no market power being exercised. It might be that Bob and his colleagues are doing an excellent job or it might be that market power is not quite the big problem that everybody thought it was.

Whatever the cause, and I'll go to that in a moment, the implication is starling and I think very clear. For the Commission, the ISOs and the rest of us, the critical policy need is not the mitigation of market power, it's the correction of market flaws that create persistent under recover of costs by needed investment, existing and new. If not corrected these flaws will threaten reliability. They'll increased consumer costs and they'll threaten the future of a competitive electric industry. These are problems that should concern everybody in this room no matter what side of the market they sit on.

Second point, it's increasingly clear that aggressive mitigation is not really needed to prevent generators in constrained areas from exercising market power and creating monopoly rents. In fact, if there's one lesson from the Commission's very interesting experiment in push bidding in Connecticut and Boston. This is it. Generators were allowed to bid at much higher levels than they ever had before, yet they were unable to recover their fixed costs. Again, the policy focus needs to shift from prices that are too high due to market power in to prices that are too low due to market design flaws.

Market power is associated with extraordinary profits and barriers to entry. Market design flaws that we're seeing; particularly in NEPOOLm are associated with extraordinary losses and barriers to exit. The NEPOOL market sends price signals that tell needed generators that should exit the market, retire or mothball. Yet, the NEPOOL market rules are reading like the fine print on the back of the door of the Hotel California. You can check out any time you like, but you can never leave this market. As long as this is the case, the Commission will have to recognize that both existing and new investment need out of market mechanisms to recover fixed costs.

The clear message is to allow fixed cost recovery and encourage a rapid move to correction of the design flaws that have prevented fixed cost recovery. Instead of putting up a fence to keep the guests from leaving, it would be much better to put up a market design platform that makes generators want to get in rather than get out.

The third point I want to make, and it'll probably be my last one, is that there's some good news. Despite the serious design flaws, tried and true market solutions do exist. New York ISOs combination of mitigation and other measures have produced a moderate level of scarcity pricing, a locational capacity market and a demand curve for capacity which was championed with vision and leadership through the New York Public Service Commission at the state level. All work together and have the potential to send the needed, long on-marginal cost signal to buyers and sellers alike.

And while these elements need some fine tuning, perhaps, they're already helping send signals to buyers that they would have an interest to issue RFPs and enter the long-term contracts like the gentleman from the financial community described at the beginning of this panel. These same basic design elements can work and will work in NEPOOL and PJM as well and they will help induce a competitive mix of infrastructure that will minimize the cost of infrastructure and electric services in those markets. But to get there, the Commission has to act decisively to correct these design flaws really before it's too late.

I'll stop there and look forward to your questions.

MR. COLEMAN: Thanks, Steve. Next we have Bob Ethier, Market Monitor for ISO New England.

MR. ETHIER: Good afternoon. Thanks for the opportunity to address you all and share our experiences in New England. This morning as I was sitting through the discussion it occurred to me that those of us from New England are especially well-qualified to speak here in front of you today because we've experienced, either implemented or had on the design boards probably more types of local market power mitigation than all the ISOs combined. It's not something we sought to do but that's where we are.

This has occurred because we do have two significant load pockets in New England and we've learned a lot of lessons from being there. I think the morning sessions did a very good job of covering the broad groundwork. I can't agree more with the idea that we need to get the prices right. What I want to do this afternoon in these short remarks is sort of highlight a few areas where I think deserve special emphasis in front of you all today.

The first one is that New England has a clear market design problem. We recognize that. We're working very hard to solve that problem. Why do I think we have a design problem? The design problem is evident because we have units in areas that are critical for reliability but want to retire. That's a very basic test. If the units that you really need to have around aren't incented to stay around in the market, then we need to evaluate how you've structured your market design.

I think one of the things that we've learned from our markets is that local market power mitigation does not stand on its own. You can't talk about it in isolation from the rest of your market design. It's really integral to your market design just like a capacity market may or may not be just like reserved markets, just like a locational energy market. The push bidding our current local market power mitigation measure, we frankly learned a lot from that and I hope all the ISOs have learned a lot from that mechanism. It was, I think, probably the appropriate policy decision at the time given the constraints that we were facing, but it is not a long-range solution, in my view.

In my view, a local market power mitigation measure that also seeks to provide full revenue recovery for

RMR-type units is unlikely to work in all or even most circumstances because it hasn't work in New England. So one of the short answers for why it hasn't worked is there's not sufficient market power to allow it to work, which is sort of an interesting consequence. There are a subset of units that it could probably for but the report that we've put out this fall shows, I think, very clearly that it did not work for the broad cross-section of units that we have determined are needed for reliability that are not able to recover even necessarily the going forward costs under a relaxed bid mitigation regime.

While it may be an appropriate short-term fix, I don't think it's the right emphasis for anyone to seek as the long-term remedy to how do you incent folks to build in load pockets. There are sort of two reasons why it's not a good long-term remedy. One is it didn't work in our experience, frankly. The other is that it does actually allow dispatching inefficiency. That is something that we can afford and we ought to avoid. It results in circumstances where you dispatch less efficient thermal units before you dispatch more efficient thermal units and it does this on a regular basis. That is not something that we should want to perpetuate under our market designs in any sort of degree, in my view.

The energy markets its important that you get efficient dispatch and one of the advantages of these markets should be that they do get efficient dispatch so you get the most efficient resources running first and the least expensive resources running later.

The next point I'd like to make is that I think local reserve markets are an under-appreciated aspect of market design. I think that's something that flows directly out of our experience with push. What we really need in New England are more local reserves. We're not paying for those reserves. That's why we're not getting them. That's why that's an important part of our market design and development plan is to get locational reserve markets with scarcity pricing probably in the demand curve. That would go a long way towards resolving some of the revenue problems that these resources have and I think it under-appreciated -- part of it also is that it takes some of the pressure off of the ICAP market and the locational ICAP market. People are very concerned about very large ICAP prices. One of the reasons that you have them is because you don't have this locational reserve market and you're using locational ICAP as proxy for these reserves. So you're paying everybody a lot even if they're not really providing you with reserves.

If you can sort of disaggregate those products and say, look, I'm willing to pay reserve resources a certain amount it takes the pressure off the locational ICAP market. It means you don't have to try to reward everybody for providing a service they're not really providing to you.

My fourth point, I guess, would be that out of market actions are a bad sign. This has been said before. We are doing them in New England but they're a bad sign. RFPs and RMRs should only be a last resort and should only be in targeted instances. A good instance in New England, it might be we have a couple of islands off the coast of Massachusetts that are never going to have a competitive market and essentially, there is generation and of course the transmission system. You can imagine a case where that would be an appropriate long-term solution. It would be an RMR contract but, in general, they should be an integral part of your long-term market design.

I guess the final two points would be the lumpiness problem, in my view, is overstated. We've had significant investment in both of our load pockets and we still have problems. I think it is the isolated example where there's one investment that solves the problem completely. In reality, it's the incremental investments that you don't get.

Finally, I'd just like to remind everybody, and I think the ISO understands this, that in the long run you can't avoid paying the costs for new entry. You have to have a market design that allows that to encourage that new entry and that's the unavoidable fact of all these markets and we all ought to keep that in mind. Thank you.

MR. COLEMAN: Thanks Bob. Our last speaker on this panel is Gunner Jorgansen from Select Energy.

MR. JORGANSEN: Good afternoon. I'm Gunner Jorgansen appearing on behalf of the Northeast Utility System. My remarks reflect end use experience in New England and addresses, No. 1, the importance of additional infrastructure in mitigating local market power and also meeting reliability needs and two short-term and long-term solutions.

Like PJM, the electrical load pockets of New England are also focal points for the debate over-balancing local market power, mitigation with the need to maintain local reliability and generators economic reliability. The key to success in mitigating possible local market power issues is having market design elements that produce efficient short- and long-term market signals to ensure infrastructure. Peak and bonus must be laid out many years in advance to provide clear, long-term market signals as incentives for generation transmission and load response enhancements.

New England's standard market design began March 1, 2003 and the resulting LMP price signals have been successful; particularly, Connecticut's decision about infrastructure. The Northeast utility system is built in their submission infrastructure to assure greater reliability and resource adequacy in southwestern Connecticut, but they're not completed yet. Attempts to get the market signal right in resource constrained areas of New England have produced a series of successive interim solutions as well as broadly different cost allocation mechanisms. These changes create uncertainty. Some Connecticut long-term requirements, not that they are piecemeal, due to uncertainty over new market rules and expect the high opinions by suppliers. Thus, efficient long-term capacity procurement from generators is jeopardized.

With this said, I commend the Commission for recognizing the need to address resource adequacy, market solutions in certain New England subregions. The New England stakeholders process is now in its 11th hour producing a mechanism that implements locational and deliverability requirements in the ICAP and resource adequacy markets from June 1, 2004, in response to Commission directives.

As I speak, the New England ISO-ICAP problem is for local areas prong to reliability of lack of power issues. This phase-in period coincides with the expected time it takes to complete certain transmission upgrades and to begin the development of additional capacity after the phase-in. The proposal creates an immediate locational capacity obligation for a local load enterprise to phased in pricing mechanisms for all the required resources in the area.

Local peaking resources, in addition, are guaranteed a common transitional payment in recognition of the local reliability role during the phase-in period. This is similar to ISO New England's RMR contractual rents accept of transitional price. Not an individual negotiated price is available to all eligible resources. All parties would have the opportunity to view the units eligible for the transitional price treatment and review the cost factors making up the transitional price.

Planned resource additions are expected to occur by the end of the multi-year phase-in. Then we envision that a New York-styled ICAP demand curve is the long-term pricing signal for this subregion. This solution is also being actively debated within New England at the moment of why is the phase-in necessary. New resources have various deployment times. Time lines mostly require three or more years, all depending on the resource technology and magnitude and local sighting issues. Thus we see the need to avoid and we did.

Imposition of long-term economic signals on current consumers when the market and infrastructure additions are incapable for an immediate response to the signal. What happens in the Connecticut-specific demand curve were implemented immediately wthout a phase-in provision. Consumers would be exposed to 6 to $700 million annual of price signals from additional resources. This is an unnecessary transfer of wealth. The phase-in arrangement provides direct revenues for high as well as low capacity units in combination with infrastructure investments. This should provide the necessary market power mitigation by creating stability in the marketplace. We see this as a pragmatic balancing of difficult issues.

The proposal following the Commission's approval would provide a well-defined set of pricing structures which permits ISO New England to maintain its role as a market referee and not become a market participant, would relieve ISO New England from competently negotiating RMR contract pricing terms under duress following by lengthy Commission rate proceedings. This concludes my prepared remarks. I'm available for questions.

MR. COLEMAN: Thanks.

MR. GRAMLICH: I had a question. First of all, I'll make a quick comment. As you know, we always try to get the balance of load and generation on these panels. Sometimes we succeed. In this case, some of the load-serving entities who buy and pay for our local market power mitigation measures have representatives from other parts of the company. We will have an open-mike opportunity.

I'll jump into the question. On the last panel a few people criticized the option of loosening mitigation if you find a case where price signals are not being sent where they should be sent and I heard, Bob, you say that can happen where sometimes you wind up with a result that you don't have enough market power to get the price high enough, which is not the problem people usually think of.

People on the last panel were saying actually the problem is you end allowing market power to be exercised where you don't need the price signal. I guess I'd like to confirm with you that you can wind up with both problems, then get others to comment. I think, Richard, you spoke about the idea that mitigation should be loose or nonexistent in load pocket areas, so if you could comment.

MR. ETHIER: That's an accurate summary. I'd elaborate slightly by saying that one of the reasons the price didn't reflect the cost of the generation is because what we were really buying were reserves. In Connecticut and in Boston, we often call on inflexible steam resources to provide reserves for long stretches of the day because we have insufficient quick-start capacity in those areas. So while these particular resources, we have been benefitting from relatively high-offer prices, there was no useful market signal sent that a new entrant could respond to and hope to receive by entering the market. So to the extent that there were increased revenues to generators, it served the need to keep the generator around, I suppose, but it didn't serve also the important need of inducing new entry. It was a combination of insufficient market power, if you will, and also what we were buying wasn't really energy, it was reserves.

MR. RAPP: I think my comment was that we understood the need for mitigation in certain instances to temper market power, but it will give you an opportunity, in response to your question, to sort of address New York specifically and where KeySpan thinks there should be some modification to loosen up mitigation as it exist today.

First, with respect to the day-ahead market, we're currently being mitigated on a 24-hour block basis. KeySpan feels that if mitigation is appropriate, it's probably only appropriate in certain hours or a certain hour of the future day. That should be addressed more specifically than having us mitigate it on a full 24-hour period.

Secondly, my remarks were that there shouldn't be mitigation as it reflected the real-time price. And because there are real-time changes, such as changes in the gas market, say, if that's our fuel of generation, they can occur over the course of the day. The ISO really doesn't have the ability to address those real-time changes and effectively mitigate us to the extent that it isn't punitive to us.

MR. CORNELI: Rob, if I might respond, also. The push bidding experiment shows two things that seem like they work in the opposite direction. One that is relaxing mitigation doesn't seem to help very much and the other is that, at least from a number of our perspectives, mitigation still matters.

The real matter here, at least from NRG's perspective, is that energy prices matter a lot. Energy prices -- let's put it this way, what you can't recover in terms of your fixed cost in the energy market you have to recover some place else, whether it's reserve markets or capacity markets. The more that can be recovered at scarcity prices or high-energy prices at times when demand is high the less need to come out of these other mechanisms. Relaxing mitigation is one way to do that. I certainly agree with David Patton's observation this morningning, that that can work in two different ways, neither of which is necessarily what anybody would want to have happen.

It seems that the critical issue here is figuring out what is to get higher, prices at times when demand and supply condition warrant that. There's obviously the reserve shortage price and there is pricing of other system actions that take place for and around reserve shortages to keep them from happening and dropping the voltage. Asking for a voluntary load, reductions, recalling extra capacity, there's a whole bunch of steps like that and there's pricing out of various different short-run marginal costs, the high end of output of a thermal unit on a hot day and when there's a higher risk of tube failure and being short in the real-time market has a much higher short-run marginal cost than the average fuel cost of that machine.

That could be reflected in bids. I think all the ISO tariffs have provisions for that sort of thing to be reflected. So I'm not sure it's used very much. It can be reflected in reference prices as is done in New York. So there's a variety of ways, both by relaxing mitigation but probably more important by making sure that the systems in marginal costs, which may be much higher than any generator's fuel costs or actually setting energy prices. Those are critical steps and I think the lesson of push bidding is that, hey, there's not as much market power as people thought, at least, in that load pocket and probably others.

If you want to get higher energy prices, as the Commission clearly did, you need to look some of these -- in the Delmarva order you need to look at some of these other measures making particularly sure that you're not using mitigation to hold people to their short-run marginal costs when it's something higher than that clearly is warranted.

MR. GRAMLICH: How do you balance that with the financial and the investor representatives who discuss the need for long-term contracts? Do you say what most of the economists are saying, which is get the prices right. If the prices aren't right -- if they're too low in a situation where there's scarcity, then get them right and David Patton and others have given some options to fix the market designs to do that. Your theory seems to be if you get the prices rights the loads for the entity must sign the long-term contract. Do you think that's going to happen?

MR. CORNELI: I think that is the basic theory. What we're seeing in the New York locational capacity market is an interesting correlation, if not a causation, and that's that we have the SES project that was talked about and the LIPA RFP, both coming out for 10-year or long-term purchases for capacity new development at the same time. That LSEs are issuing these RFPs and facing a locational capacity market. Energy prices, even when mitigated, can be in the multiple hundreds of dollars and a capacity market with a demand curve that holds capacity prices up so that the expected cost stream to a buyer is high. I think what you're seeing is likely to be those buyers seeing prices going up above the cost of the contract and sellers who are going down below the cost of the contract. Their getting together and saying let's make a deal. I think that works.

MR. FALK: What I was going to say about that is essentially the same thing. In a world in which prices are held down, it shouldn't be surprising that no one has any great interest in signing a long-term contract. They think they can only lose on such a deal. And so it goes back to what was said at the first panel, if the prices are right and are truly reflecting these things, it would then be in the load's interest and the mechanisms where they're allowed by the state commissions or through the load's own self-interest, I think will develop because they don't want to be whipsawed any more than anybody else.

MR. WEMPLE: Rob, just from the perspective on LSE, my retail affiliate, Con Ed Solutions, does have a lot of load. On getting the price right is right for a couple of reasons, it's not going to make any retail LSE go out and hedge longer term than its retail sales are, to do so would be a speculative position. So for a couple of reasons it's important to get the price signals right. It might make regulating utilities a bit long-term. Regulatory compacts do something different, but a retail LSE can't afford to go out and buy a five-year contract for supply if its retail sales are only a year and a half in duration.

The reason it's important to get the prices right is because the uplift, which is an unhedgeable cost, is financial suicide for marketers. For us to guess at a price and convey it to the end use customers, we have to pad uncontrollable prices a lot because you can't control them by definition. You don't want to be on the wrong side of the equation. It also dampens out whatever demand response you were hoping to get for the limited customers who are willing to switch fuels or do something different in reaction to the right price. If you're not generating that right price in the first place, you're not going to get the demand response you want.

MR. REEDER: I wanted to comment more about -- there were some comments that peakers are something you can't recover anything more than their valuable cost. I think it was pretty clear but that's true if you have no decent rules for scarcity anywhere. But if you have decent scarcity prices, they definitely can.

In New York we have demand side that bids, 200, 300, 400, 500, any of those can be on the margin well above a peaker. If you don't have enough of that, the price could go to a thousand if you're short of reserves. So let the scarcity itself, if it's truly occurring without withholding, drive the prices to the 200, 400, 500 or a thousand and the peakers do fine.

So in some of the situations it may just be the lack of enough scarcity, but that raises the locational ICAP concerns because enough scarcity to produce compensatory revenue streams for a peaker without any ICAP may be way more scarcity than society in New York City and places like that want. So the ICAP market, in essence, is saying we don't want to push scarcity that far. So it has enough for days when we're really short to be compensatory. We're going to compromise by giving extra revenue streams for ICAP so that scarcity doesn't have to do it. But please, peakers can get revenues well above their running costs by bidding their running cost every hour. The studies David Patton has shown show that. They're not fully compensatory because we have excess in a lot of places.

It's certainly not proof if generators are allowed to exercise market power and they cannot raise prices to their long-run average costs. That's not proof that they don't have market power. Many markets get gauged. They get surplus and the natural competitive price. You get a thousand players, each with a 10th of a percent of surplus, is pretty low. The natural price, if you only have six players with surplus, may be significantly higher than that but not all the way up to the long-run average cost. So market power can pull you above the competitive level but still keep you below that sort of long-run average cost.

Just one other thing, I think there was a comment that there hasn't been much mitigation, much market power. Well, New York City has had it mitigation measures triggered just constantly. So the fact that you haven't had really higher prices isn't a sign that you haven't had market power. It is a sign you haven't had market power, but it's not a sign that you should feel free that if you lift all the mitigation measures you would continue to not have market power. The reason you don't have the market power is because the mitigation is kicking in a lot.

MR. SINGH: Mark, you mentioned earlier that when set the demand curve for reserves you should take into account the revenues that you get from energy and from the ancillary services markets. So we heard this morning of scarcity pricing for energy and scarcity pricing for reserves and, obviously, the demand curves. It would seem then that we have some digress of freedom. We could pick one really high and then the other one would be lower because you have a very high cap in the energy in the way you set up the administered scarcity pricing there.

Your demand curve, presumably, for ICAP would come out differently based on what you said earlier. Are there limits or bounds on how much we can tweak this in the extreme? You could certainly get rid of ICAP if you have a very high bound on the energy side. Do you have any thoughts on that?

MR. REEDER: You're exactly right. A real world example, when we were doing an analyze of what the demand curve height should be for installed capacity, we had to make an adjustment because we used historical data, which produced the amount of revenues peakers get from the ancillary services data. But we noted, wait a minute, we just load for scarcity pricing rules that aren't in last year's data. They will be in next year's data. We need to adjust upward what the peakers will get from the energy market when the new scarcity rules go in and that let's you adjust downward as you suggested.

The demand curve, in the limit, if you get enough demand response, that is your way of responding to load growth for the next 20 years, let's say, real-time pricing, things like that and that's what you get instead of peakers or instead of generation. Then instead of peakers on the marginal lot at $100, you have demand response on the marginal lot at $250. You can get a world where the energy market is fully compensatory to hard wire generators called peakers without having any involuntary blackouts. The one day in 10 years is fine. That's an involuntary proposal. When you have voluntary people cutting back, the price clearing at 200, 300, 400, everyone who wants power gets it.

The peakers make plenty of money. The ICAP market can go away. That might be a dream but that's a long-term view that we could try to strive for and that's how I think it could work.

MR. FALK: I just wanted to say one quick thing about what Mark said. I don't want to not characterize New York City as a load pocket. If we were going to start defining our type of load pockets, I think New York City would be one. But you cannot draw the conclusion just because the market mitigation measures have been used a lot that the market mitigation measures have necessarily been effective since, after all, the bids people make they make with the knowledge that they're about to be mitigated. So we don't know what the regime would be like with a different set of mitigation measures.

Now I'm not saying that New York should be immediately set loose, but I think that there's a real threat here that I put on a market mitigation measure and you say, see, look, it worked because I mitigated all these bids around. But of course, you bid differently in a world where you know you have a backstop that someone will change your bid down to your marginal cost if your bid turns out to be too high. So you have to take into account what people's incentives are in the bidding. They will always be conditioned on whatever the mitigation happens to be. I don't think that necessarily goes to the New York City example, but I think it's an important point to bring out in general.

MR. ETHIER: Harry, you mentioned it seems like we have some degrees of freedom and I think you're exactly right. But I think we need to recognize that there are some real implications of how exercising those degrees of freedom, what that will have on the resource mix. The two obvious ones are the thousand dollar offer cap. If you were to lower that substantially, you may reduce the amount of demand response. You may get fewer megawatts for emergency ranges of units, which, for example, in New England helped us out a couple of weeks ago. So you want to be careful about precluding resources from participating in the market.

And the other one that nobody's even had to grapple with, with any luck New England will have to soon, is if you look at the demand curve reserves, depending on how you shape that, you can dramatically change the incentives for what kind of resources you're bringing into the pool.

In New England it's pretty clear at this point we need quick-start capability. We're on record with that. But in the long run, it's unclear to me how you make clear lines about how much of each resource you want. That's a problem that we'll have to deal with down the road, but I just want you to be aware, you're right, you can mix and match, but you're going to get downstream implications for the underlying physical facilities you get in your marketplace.

MR. O'NEILL: Some of you made reference to calculations about not earning your capital costs. In a market that's got excess capacity, wouldn't you expect that to be the case and in a market that was short, wouldn't you expect that number to be higher and what are the implications? If you want us to do something now when the market is in excess capacity, shouldn't we do something when the market is growing short?

MR. FALK: There's no question that in a gult you won't earn your capacity costs back. That's simple economics. The flip side of that is, okay, then let me mothball the unit for a year. Let me take it out. I'm not going to make even my fixed O&M on the unit. I want to be able to leave the market. If you're stuck in the market to simply bear those costs, that sounds like a taking to me.

MR. O'NEILL: That's a fair point but that wasn't the question I asked. What lesson should we take from the fact that in a glutted market you're not earning a return until, let's say, a standard cost of service calculation.

MR. CORNELI: Let me take a shot at that and see if this gets to your question, Dick? There's a glut globally but there's not always a glut locally. For example, there's the constrained areas of NEPOOL that have actual shortages of the needed level.

MR. O'NEILL: I was being generic. I wasn't trying to hone in on anything specific, but you raised the point about not earning in a glutted market enough to cover a cost of service calculation. If we're to act on that when you're not earning enough, there's an implication that we should be acting on that when you're earning too much. I'm not sure either one of those is a good strategy.

MR. CORNELI: If you took from my presentation that you think we ought to be paid the clear cost of service.

MR. O'NEILL: I didn't. It was others.

MR. CORNELI: I think the way that ought to work is that if there's a shortage you should be earning more than your full cost of service and if there's a glut, you should be earning less.

O'NEILL: There's no real full cost of service calculation.

MR. CORNELI: Let's put it this way, you should be earning enough.

MR. O'NEILL: Over the long run, you should be earning enough to earn the return on your investment, but the short day-to-day calculations or year-to-year calculations can give a very misleading signal, so you take them over a very short period of time --

MR. CORNELI: I think on a shortage situation the misleading thing should be that you're making more money than you'd like to later rather than you're making less money than you'd like to later.

MR. O'NEILL: In a shortage situation, yes, but the problem is if you keep pointing out to us that you're not making enough money based on this calculation and we should do something about it, the implication is that we should also do something about it when you're earning more than that number.

MR. WEMPLE: Richard, if you look at the historical levels, say, from '99 through '03, we've been under recovering and the next two years we expect to also be there. One would expect a comparable period of over recovery. I know it hasn't been the Commission's policy to preclude over recovery, but the political reality is when the prices jump up there tends to be a bias towards additional mitigation, additional price caps. I do not have confidence that the political environment will allow people to over recovery for a sufficiently long period of time during scarce situations to offset the under recoveries we've had for the last four years.

MR. O'NEILL: What's your solution?

MR. WEMPLE: Market reforms to have more rational outcomes and I think the capacity market behavior going to zero in New England when units are needed suggests --

MR. O'NEILL: I thought we just agreed that the rational outcome when there's excess capacity is you don't make that number?

MR. WEMPLE: But to fall as far down -- nobody's suggesting in a surplus market everybody should get their return, but we've had such a cycle and gone so far from where new entrants need to be for anybody to have confidence to put more merchant money at risk. We have to have an expectation that you'll have enough years above and enough years below, and the last four years have been so far below and the next two years are also going to be below. I've got six years of history that says the market's not going to compensate a peaker. I have no confidence we're going to get six years of over collection.

MR. O'NEILL: But the lesson we should take away is that we should get the market design correct, make sure there's appropriate scarcity pricing, but not to try to compensate you over or under that number.

MR. WEMPLE: I agree.

MR. FALK: I think we all agree on that.

MR. PERLMAN: Can I ask a question about that, gentlemen? From my understanding from what you were saying is that you were adverse to any kind of mitigation.

MR. FALK: You have to read the long paper not the short paper, but, no, that's not right. I think my paper comes from the observation that we seem to be so afraid of market power that we're probably over mitigating but that doesn't mean, I don't believe, that there are certainly all kinds of situations in which mitigation is warranted. The most classic example, if you think to the auction proposal, the auction proposal which we want to get enough resources into bid in one of these situations and it might take three to four years to bid mitigation for that entire period up until that new resource could come into line. There's no reason for the incumbent generators to simply earn monopoly rents for the period that it would take to build their competition. There's no obvious productive efficiency or any other sort of result from that. It's not that I'm opposed to mitigation. It's that you have to think about why you're mitigating, who exactly you're helping and who exactly you're hurting and what you're doing about long-run productive efficiency.

MR. PERLMAN: I understand. But what I think we talked about this morningning was the structure where you have scarcity pricing with the administratively set component for the scarcity and operating reserve component but with relatively robust mitigation in the energy market sort of when those things were not impacting prices, so you would end up with sort of with a mitigation structuring today but with additional opportunities in times of scarcity or however we define them. Is that something you'd be comfortable with?

MR. FALK: I agree with that but my takeaway with that is that once the prices is right, and I think Bill said that mitigation problems present themselves, it's actually now a much smaller set of units. It's a much easier to define set of problems and you take them on one at a time.

MR. TIGER: A follow-up question on, perhaps, we have this question about the mitigation in New York and it's mitigated 50 percent of the time in the day-ahead market and presumably we have these debates internally about whether the market signals are being sent in situations where there is that kind of mitigation. Presumably, there are projects on the board. You mentioned two of them, specifically, New York load pocket. Maybe you can talk a little bit, both of you, in terms of capital looking at mitigated prices and how you compare the PPAs that are underlying projects versus the market prices that you receive that may have an administratively determined component and a market component.

MR. ANDERSON: Jonathan, I might take a first crack at that. You have a broader perspective as an advisor on these, but here are two topics and these is meant to be somewhat responsive to your point, Mr. Gramlich about what do we mean when we're talking about contracts. I hear some discussion about there needs to be a price signal that will tell capital you can get your return if you come when you get to the point that you need new capital to come in and build peaking units. My comment about me providing long-term capital for power infrastructure is a little separate topic as one of needing a signal to get capital in and the second separate topic is what kind of capital are you attracting? Do you have a volatile system where someone with a 25 percent return requirement says, okay, I've now got a rate design that will allow me to deploy my equity capital in here and take a bet on building a peaking unit? Or do you have something with more predictability and a long-term contract that the debt investor can rely on and that has to be backed up by the load-serving entity seeing his ability to pass that through? If you do, you've now unlocked 7 percent return capital, to use an example. So you're blended cost of capital and return that the ultimate user has to pay it is now 13 percent instead of 25 percent. So I hope that puts a little bit in context my narrower comment about contracts versus the broader discussion of a level of returns has to be high enough to attract capital.

MR. O'NEILL: It sounds like a great deal for the buyer.

MR. ANDERSON: That's right. That's the power of unlocking some debt capacity in this market as opposed to having it be so volatile that, while theoretically complete, it's an equity only market that's going to be a more expensive proposition for the ultimate consumer.

MR. O'NEILL: And I guess the culinary is it's going to be more expensive if you want to live in the spot market than it is if you basically sign long-term contracts that follow the rest of the investment?

MR. ANDERSON: That's right. In the long-term contract for your full requirements you'll never get it right, so you try to figure out that right mix of how much you can make a long-term commitment for and how much you need to leave open because you know the future will always be different from any one projection, but we agree on the basic premises.

MR. BALIFF: I think the nature of what you're hearing from us is that your return market is the signal, okay? Unfortunately, I can't comment on the angel's dancing on the head of the pin. However, I can tell you that that market, to get it right is important because it is going to be the basis of these contracts which, again, are the necessary but not sufficient condition. That being said, and that's by the way, is the 7 percent money. You're looking at the 7 percent money. We're having access to the 25 percent money. By the way, that doesn't mean that this money is smarter than this money. To say that there have been dumb investments in this sector is an insult to dumb investments.

(Laughter.)

MR. BALIFF: But the idea is if you want to create the solutions that are long-term solutions not short-term solutions, you need to be able to have the right market. If it's a dumb investment, just like Bill said, you lose the money. So what, you know, that's the risk that you take. The issue that we're getting into from our side is the risk measures almost compound each other if the investor has to take construction risks combined with commodity risk combined with regulatory risks. This is when you actually start to see the market shutoff and you don't get investment. There's a mix with the short-term and long-term investors certainly who come into this market.

Right now we're on the cusp primarily because we have so much liquidity that it might actually be masking some of the problems that would be inherent, i.e., a shutdown of the marketplace. Right now you don't have that. I can tell you, you also don't want to have very hot money. We're talking about the left side of the balance sheet the way I think, the asset side. You want to have -- that's very volatile given the nature of our market. Do you want the right side of that balance sheet also to be hot money coming in and out? I don't think so. That's why we need to have some of these risk mitigation measures.

MR. PERLMAN: Can you describe what you mean by "regulatory risk" and how we can act to reduce that risk?

(Laughter.)

MR. BALIFF: I think the example of probably the regulatory risk, for lack of a better word, that freaks out the investors the most are the reg out structures that you saw in PPA contracts. And again, those were mostly -- they can be state, but it's less (inaudible) based, okay? So if you have a long-term, let's say, five year contract or we have this 10-year contract with Con Ed for the SES plant -- I can tell you there are none of the reg outs that you saw in the California contracts.

The investors are kind of fool me once kind of investors. So don't think you can have that type of reg out, but they're also concerned with rapid significant market structure changes. Again, fool me once. They're not going to be basing their cash flows on any type of rate caps. I'm sorry, they'll base some of their caps, but nobody going to think you can get greater than a thousand dollars. That's for the equity. That's not for the debt. The debt is really going to placing in their own performers and their calculations a certain amount of what they consider as reasonableness for the markets that are allowed, and if there are rapid changes, that's the regulatory risk that I'm talking about.

MR. COLEMAN: Now that we're getting ready to go to break, to take a couple of minutes, as we said at the outset, if there's anyone from the audience from the load side who would like to make a comment we have a mike right here. I would just ask that you'd give your name and your affiliation for the court reporter so it can be transcribed.

MR. SASSON: My name is Myer Sasson from Con Edison, the regulated company for New York City. I welcome very much, Michael, your idea of the LSE viewpoint. There are lots of ideas going through my mind from what happened this morning, which I think was very, very good.

I'd like just to say that the transmission owners in New York had a tight pool for about 25 years before the New York ISO was created. I was part of the team that formed and proposed the New York ISO to the Commission to emulate the New York ISO 25 years of experience all the way from mandatory rules to liability rules to capacity markets, locational capacity markets and we have locational reserves. We had them before. It was not a deregulated market but we had all of those because they were all needed to keep the lights on. That was the bottom line. I think that was emulated from the New York ISO.

Right after the New York ISO was formed and we started operating we did have to fix many flaws in market design. We did not have the sophisticated mitigation measures that David Patton put in that addressed the real situations, especially in New York City. New York City has load pockets. As a whole, it's a load pocket but inside New York City there's many, many subload pockets; yet, it works well.

If you look at prices in New York City in the past month where we've had high gas prices, we've had very high prices in New York City. The prices in New York City do reflect what -- it's been the highest price in the state. That is the right mix of prices that we should have because New York City is the most congested portion of the state. Where is generation? This morning it was very clearly stated. Where is generation on site in New York City where people are thinking they should be building transmission into New York City? I think we have a market that has the right balance of mitigation, scarcity pricing, locational capacity, locational reserves that is providing the right signals for generation and transmission to want to build.

The last point I wanted to make, a couple of quick points is, and I think David and somebody else also said something about this this morning, you don't necessarily relieve a load pocket by building transmission. That may not be the right thing to do. If the market wants to do that, that's fine. From a merchant point of view -- but New York City is reliable with it's load pockets. Remember, it was designed that way. When the vertical utility had existed, it designed New York City with all its load pockets as the most reliable utility in the whole world and it still is.

The idea that load pockets mean unreliable systems just doesn't add up. We operate to a second contingency in New York City, a higher availability measure than anywhere else and we are reliable with our load pockets. So if, from a merchant point of view, there's a thrust to build into New York City, that would be great. That's fine. But it's not necessary from a reliability. We need to keep that balance in mind.

The last comment, not to abuse what you have offered me is -- it's an open mike.

(Laughter.)

MR. SASSON: Is that we had an RMR problem in New York City because of all these load pockets and subload pockets it was very difficult for all of the market design to bring in all of the reliability requirements into the market. So very frequently our operators in New York City needed to say we need to increase generation, take it out of the market and we'll call it out of merit. It's an RMR for a few hours. Yet, we work hard with the New York ISO and came up with changes in the market design that were able to bring the RMR into the market design so that now the selection of the RMR unit, and there may be more than one unit, that must run at a higher level in a given load pocket to resolve the reliability problem is no longer dictated manually. It is within the market rules. It effects prices and, yes, there is mitigation and it is subject to mitigation. With mitigation, we have had high prices in New York City and I think that is the right mix. Thank you very much for giving me this opportunity.

MR. KATHAM: Can I ask a question that has to do with -- we've been talking in the first panel and this panel about LSEs and signing long-term contracts. Could you speak to Con Ed's decisionmaking and why it decided to go and sign long-term contracts?

MR. SASSON: I would rather not address the question right now. There's a reason for it and it is that my involvement has not been close enough to that decision to be able to do merit to your question. It's a very serious question. We would, in written comments, reply to it. We were advocating the need that in capacity markets we do need more long-range capacity structures than we have today, and the reason for that was we were convinced that the financial markets needed more long-ranged signals, steady signals than a six month-to-six month capacity market that we have today. That is one thing that we're working on. The very, very specific issue you're mentioning we'll address.

MR. COLEMAN: Along those lines, Jonathan, you said that Conjunction Project -- project as well.

MR. BALIFF: Auction is following the FERC rules for an open season. That auction will commence at the end of February. We will be going out with contracts. What we are seeking, though, is actually not one player, even if Con Ed came in -- maybe we'd make an exception.

(Laughter.)

MR. BALIFF: The idea is we'd like to have diversity of contracts very similar to what you see in the gas pipelines so that you don't have -- it'll be easier to finance in the marketplace because you'll have diversity, but we have to follow the open auction season.

MR. PERLMAN: I'm sorry. Thank you for point that out. Do you have a duration of contract that you're going to need in response to that process to get financing?

MR. BALIFF: We are looking at 10-year contracts as the heart of the envelope. It is an open market process that the FERC designates for good reason, and really what we're going to do is follow what the market tells us it can do. And obviously we have to cross-check to make sure it's financiable, but it's an interplay between the term of the contract and the price of the contract. And in these financing markets, the good news is we can accept some things that we probably couldn't accept four or five years ago because of the low cost nature of the capital markets.

MR. O'NEILL: Would you do anything differently if we didn't have open season requirements?

MR. BALIFF: Yes, we would.

(Laughter.)

MR. BALIFF: I think the nature of what we'd want to do in transmission is to try and make it look more like gas pipeline and power gas pipeline.

MR. O'NEILL: They have open seasons.

MR. BALIFF: But it's a different type of open season. I'll put it this way, what would I do differently? I'd like to take a hiatus for 5 or 10 years, have a couple of more open seasons happen, then come back and start financing. It's a very difficult process now because the open season on gas pipelines is such a tried and true measure. The nature of that market in getting the open seasons more toward negotiated contracts is just much quicker. There's less uncertainty. An electric transmission, because it's all so complicated, though, because of the nature of our contracts cannot be physical contracts. That's a huge difference. The physical contract for a gas pipeline, which is under an open season, means the offtaker has physical capacity. In electric transmission lines you do not get that because of the nature of the New York ISO says that you cannot have that. They must control the line.

MR. O'NEILL: Even in the D.C. line?

MR. O'NEILL: Even in a D.C. line.

MR. COLEMAN: Our time is up here.

MR. O'NEILL: It would be nice if we could understand the differences between the gas and electric open season that you would like to see.

MR. COLEMAN: I want to thank the panel. I have 3:14 by the clock on the wall. We're going to take 10-minute break and get set up for the last panel. Then we're going to start promptly at 3:24. Thanks.

(Recess.)

MR. COLEMAN: Okay, folks, we're going to get started with the last panel here. Out of courtesy, if you could sit down or move your conversation outside.

We're going to get started here with our last panel this afternoon, as we have in the morning, a more board overview of some of the RMR issues. We just finished up with a panel dealing with Northeast issues. This last panel is going to give us some insights into some of the local market power issues in other regions of the country which we haven't addressed yet. So we'll have a panel that covers a much broader geographic spectrum. We're also starting off with a financial perspective on this.

The first panelist here is Howard Newman, Vice Chairman of Warburg Pincus. We're delighted to have you with us, Howard, for a comments. Thank you. You have five minutes to impart all your wisdom upon us that you'd like to.

MR. NEWMAN: Thank you. I don't have a lot of wisdom to impart to the technical part of this panel. I'm delighted to be here today. Warburg Pincus is a specialized private equity firm with significant experience in the power business. We were financiers of a company called the Jamikowski Company in the mid-80s which developed a lot of power plants in the New England market around the Iroquois pipeline. We got out of the generation business in the mid-90s and entered it again in the late-90s with an investment in a company called Competitive Power Ventures and two other companies, one of which was called Nuclear Generation and one of which was called Insight.

We have some experience in being on the supply side part of the energy markets, and I think my comments here today would reflect how we view the issues from the supply side, and to some extent how some of the issues in the must-run issues relate to that. From the perspective of a supplier of capital, what's most important to us is that we go in a system where the rules are well-defined, clear and stable. They provide adequate opportunity to earn a return on and of capital. That's the long and the short perspective of what it means to be a provider of equity here.

In making those assessments, you balance the opportunities and risks against the opportunities in other investments and we can look at this in a competitive sense, in a market sense where the market is the market for our capital. To put that in perspective, Warburg Pincus is a private equity firm. It currently has investments in private and public companies worth around $10 billion and has around $5 billion available for new investment as we speak, 60 percent of which is dedicated to the U.S.

We are aggressively and actively looking for ways to get involved in the generation business, and to date, have been unable to discover the opportunities which works. As we look at the generation business, there are two parts to it from our perspective. One is the energy margin, which I think is the part of the business which we're very comfortable with.

The part of the business which we're not comfortable with is how we see what people refer to as "capacity revenues" or the return on excess of the energy margin. And as we've looked at the market structures which people come up with, issues about whether you should rely on price spikes for 1 percent of the time or whether you can rely on an ICAP market or things like that. Those are the issues that are most important to us. What we need is some clarity and some permanence on how those mechanisms will provide revenues adequate to support the capital which we provide. That's the perspective I bring to this.

I think I will do something most speakers won't do, is cede the rest of my five minutes to somebody who's got some more technical comments.

MR. COLEMAN: I appreciate you ceding your time to us, Howard. Our next speaker is Danielle Jaussaud, Director of Economic Analysis and the Market Oversight Division of the Texas Public Utility Commission. We're very pleased to have you here to give us some observations about what has happening in the great state of Texas.

MS. JAUSSAUD: Thank you. My name is Danielle Jaussaud. As you said, I'm with the Marketing Oversight Division of the Public Utility Commission from Texas. I'm going to talk about the experience we have had in the ERCOT market with load pockets and generation pockets.

The ERCOT market is a zonal system. We have five zones and five commercially-significant constraints. Inter-zonal congestion is resolved through redispatch and through zonal bond and the costs are directly assigned. Inter-zonal congestion costs are hedged TCR auction by ERCOT. Internal congestion is solved through redispatch. In this case, the costs are restricted to loads. It's applicable to all loads.

Local congestion costs in ERCOT have been very high between July 31st of 2001, when the market opened, and June 2003. Local congestion costs amounted to $550 million. Of these, about $60 million were for out-balancing energy and about $50 million were for down balancing energy to solve local congestion problems and to solve those problems when a competitive solution existed in that local area.

In June 2003 the total balancing energy costs resulting in local congestion was $58.8 millon, which was more than half the total amount since the market opened in July of 2001. So we run into a problem because that the method that we were using for solving local congestion was faulty. I'm going to explain a little bit why it resulted in this problem.

Under this method for solving local congestion, bidders submit a resource-specific opening bid if a market solution does not exist ERCOT deploys energy from needed resources out of merit. Selection of the unit to be deployed is based on the unit's chief factor times the premium bid absent the market solution compensation for out-of-merit is based on generic costs plus a percentage. The percentage has been 10 percent.

Now a market solution is defined as three unaffiliated resources that someone bids to ERCOT and than solve a circumstance of local congestion and no one bidder is essential to solving the congestion. If a market solution exists to solve local congestion, the resource selected is paid according to the bid premium that is submitted. Some resources do not want to be deployed. For example, many combined cycle units do not want to be deployed. They do not want to decremented. For example, cogeneration base-load units load nuclear and so on. Resources were at some point instructed by ERCOT that if they did not want to be deployed they should submit a premium bid of a thousand dollars, plus a thousand dollars if it was incremental energy minus a thousand dollars for decremental energy. That would indicate to ERCOT that they should not be deployed except as a last resort. That approach turned out to be ineffective. It was ineffective because bidders did not know when there was going to be a market solution and they didn't know when to bid competitively.

There was no incentive to bid competitively and most bidder did at cap level to indicate load deployment and that was also due, in part, to faulty deployment mechanisms of some plants like the combined cycle plant. The market solutions existed in less than 5 percent of the cases. This is what we found. The approach was ineffective because no disincentive existed to discourage generators from building new generators and there was no incentive to build where generation was needed.

In June 2003 what happened then was that a market solution was created when a new generator built in a constrained area, which happened to be a generator's pocket. This resulted in this high cost of almost $60 million to the market in just one month. Immediately following that, ERCOT's stakeholders committee voted to suspend the market solution so that after that the competition was based on generated costs only, even if there was a market solution. A taskforce was created to explore alternative payment options and another taskforce was created to look into possible infrastructural improvements to relieve the severe congestion that existed in that area.

The issues that the new solution needed to deal with is that we needed to find a way to provide incentives to bid competitively where our market solution existed or exist. We needed to attract investments where new generation is needed. We needed compensation that is attractive but not so attractive as to create inefficiencies, and we an experience with that previously, where compensation for RMR was so attractive that a unit seems to prefer being an RMR unit rather than play the market and it was an inefficiency that was created. We needed compensation that would assure efficient deployment. In other words, we didn't want compensation that would lead to the deployment of inefficient units before efficient units were deployed. We needed to recognize that resources cannot move easily nuclear, hydro, cogen, et cetera.

Finally, we needed to have a solution that would have a moderate price impact. I'm pass my time and I can stop here and maybe pick up with questions later on or in the discussion.

MR. COLEMAN: Thank you, Danielle. Actually, I see our next speaker is sitting between Texas and California. And I think in terms of having a person to deal with those markets, he's probably the best person we could have here. John Meyer from Reliant Resources. Thanks for showing up, John.

MR. MEYER: I want to thank the Commission for inviting me to speak today on local market power mitigation. First, just to kind of give you a taste of the issues that Reliant's addressing, we operate in essentially all the ISO markets except New England currently. We have roughly 5000 megawatts of supply in PJM, 3000 in MISO, 3000 in New York, about 3000 in the Southeast, mainly, in Florida, 1000 in

Texas and 4000 roughly in California and southern Nevada. We also have about 13,000 megawatts of peak load to serve in ERCOT and several hundred megawatts outside of ERCOT in various markets as a retail provider.

Having said that, I'd like to kind of get to the crux of the problem. I kind of feel, speaking last, particularly after the last two panels, like a father who'd handed his son his fishing rod and reel. His son has thrown the line out in the water and it's all tangled and he hands it back to you and he says, will you fix it. e're going to try to reach a perspective a little bit on this, but we've had a lot of different comments today to deal with.

First of all, I think we'll generally agree that this is not an easy problem to solve. No one has really solved it yet either. We could probably also agree there's not going to be a perfect solution or a "correct" solution to the problem. There's going to be a solution we can come up with. We'd also probably agree that we need to protect the customers by preventing an uncapped or unheeded exercise of local market power. However, one speaker did set this right. We need to define market power correctly. That's the ability to change price different from a competitive level for a significant period of time, and I guess we could argue about what each of those components means but not today. I hope we can agree to some general principles and that's kind of the way Reliant has approached this, to lay out principles that may be needed.

We've come up with three basic things. Many of them have already been talked about today, but we hope that we can develop objective standards that define when mitigation is required in a local sense. I guess, first, we have to ask ourselves the question whether this is a temporary local market power problem. In other words, the line is out, the generator tripped off line, different loading pattern today, or is this chronic. In other words, is it predictable and it occurs quite a bit of the time, hundreds of thousands of hours during the year? Then, as we look at do we need to mitigate this congestion occurring, and I think this is something most ISOs worry about, if there's no congestion, obviously, why mitigate?

The next problem, as Danielle mentioned, is we believe there should be some competitive test or solution test that tries to identify whether there's sufficient bidders or not. Not everybody goes this far, at least, not in what I call near real-time like hourly or daily. Some people have done studies that last 5 or 10 years forward.

And lastly, we need to make sure the bids are above some competitive cap. When I say a competitive cap, it's a cap associated with that local market power condition or the real value of that. Having said that, we need to develop that standard. We also need to provide price signals that incent a long-term market solution to solve those constraints that we're worried about where there is the potential to have market power. We've had a lot of discussion on this issue that the compensation to generators or suppliers needed for reliability should be consistent with the competitive outcome, and I would add for that load pocket.

I want to point out that competitive outcome isn't necessarily the same, as some have said, as the same competitive outcome as when you have an unconstrained case with no constraints. Those are different levels of competitive outcome to me and we've mentioned the compensation for that also should recognize that those units in that load pocket provide a unique and valuable service.

Reliant has offered, I believe, in different dockets, two different ways to solve this. Our current approach is what we call a "systems survey unit" which looks at the highest priced unit in the system on an annual basis and establishes that cost as the cost of the cap in all load pockets. The other way we've approached it is one the Commission had adopted previously as a proxy new entry CT, which is more of an administrative approach. However, it's still probably a good way to do it. So either a systems survey, which is more of a market approach or some administrative approach with a proxy for a new entry.

Lastly, our third principle is you need to provide an exit strategy. No matter how well we can set the price or set a cap for those that might have market power in that load pocket, we will miss on some units and that those units that are inefficient will not recover their money and they should be allowed to retire. And we need, I think, for fairness and for reliability to develop a proper exit strategy that could lead to an auction that actually, one, provides the corrected measures for that strategy and also it values the exit strategy.

We had some discussion earlier on who does the auction. I think it's somebody that's a dependent. Having said that, I always felt the RTO should do it. Other independent parties could also do that. I think Danielle pretty well covered the ERCOT situation. I might just mention that the competitive solution test that was utilized there was three unaffiliated bidders where no one is pivotal. That was actually done. We intended it to be done prior or ex ante. It was actually done ex post, very ex post in settlement. It had limitations as Danielle mentioned. One, because we had portfolios zonal bidding with option unit premium bids that kicked in for the competitive test. That proves somewhat unworkable.

The other large problem we had with it, as she mentioned, is we had an inappropriate allocation of costs which basically spread and muted all the signals and that compounded the problem of trying to create adequate behavior. So I think some of those lessons need to be considered, of course. LMP is a jump start compared to zonal bidding. With at, I'll stop for now and try to answer any questions on other items.

MR. COLEMAN: Thanks, John. Next we have Judi Mosley, Director of Wholesale Customer Relations at Pacific Gas and Electric, and similarly, I believe, has been involved in a number of the RMR contracting implementations in California. We're glad to have you here, Judi.

MS. MOSLEY: Thank you. It's good to be here. We've heard a lot today about different things we should do in the market to correct the problems of local market power. I'm not an economist and I'm not going to wade into that debate, but I do want to say that that is the place to fix this problem.

I come here today with a different perspective. I come here today to talk about some of the experiences that PG&E has had with RMR contracts and some of the frustrations, quite frankly. So I'm hoping you'll agree with me that the RMR contracts should only be used as a last resort. We've really got to get the markets right first. The use of our RMR contracts has been very widespread in

California anyway. And while the older units may require an RMR contract in order to keep running in a load pocket, it seems to us that RMR contracts aren't really necessary for the newer and more efficient units. Those units should be encouraged to participate in the markets and get their energy to the market in that way. If a unit is economic, there is no reason to assume that it wouldn't be running under normal circumstances.

I wanted to go into a little bit more detail on the particular RMR contract structure we have in California and some of the problems that that's caused. There is two types of RMR contracts in California. Under the first type a generator receives an availability payment to compensate it for keeping the new unit available. Then when it's dispatched, it also gets a predetermined valuable cost payment.

Under the second type of contract, however, the generator is actually removed from the market. The availability payment it receives from the ISO covers the unit's full fixed costs. This second type of contract, which is known as "Condition 2" has caused some really insidious market distortions in California.

First, by removing these units from the market, it actually increases the scarcity of generation which increases the cost of generation on the market, including energy from other plants owned by the same entity. But second, customers can actually kind of wind up paying twice, and I'll tell you what I mean by that.

The Condition 2 units have been removed from the market, they're not producing energy and ancillary services. Consequently, PG&E is required to go out and procure energy and reserves from other units, even though PG&E's customers are paying the full fixed costs of those units, the Condition 2 units that are largely idle.

As the Commission recognized in the Devon Power case last year, RMR agreements should be a last resort and the proliferation of these agreements is not in the best interests of the competitive market. We agree wholeheartedly with that sentiment, particularly when it comes to these Condition 2 agreements, and we urge the Commission to eliminate these types of contracts.

The Commission has gone to great lengths to establish and support competitive wholesale energy markets. We think that, to the greatest extent possible, we need to support those markets by requiring that units run in those markets, rather than subsisting soley on the RMR payments.

Although I'm not going to get into the details of pricing in the market as a whole, I do want to talk a little bit about the pricing of RMR contracts. I think the guiding principle really needs to be one of neutrality. RMR generators should be no better off and they should be no worse off than other generators.

So, under the net incremental cost approach, RMR generators are compensated for all costs associated with RMR obligations. So, for example, if you do have a older uneconomic plant that is needed to run to support reliability of the grid, they will be paid an amount sufficient to cover the shortfall between what is forecast to recover in the market, if anything, and its ongoing cost of operations.

If it can make more in the market, it keeps the profits. That way, it has every incentive to participate in the market. The advantage to this approach is that RMR owners are compensated for all of the costs of RMR obligations, local market power is mitigated because there is no monopoly rents. RMR owners are encouraged to participate in the market, and they don't have a competitive advantage over other generators.

There is one other issue that I think merits consideration today. Once you figure out the best way to price an RMR contract, you still have to figure out who should bear the cost. Pursuant to the Commission's efforts to eliminate rate pancaking, PG&E's transmission costs are spread to all users of the California ISO system, but RMR costs are borne exclusively by PG&E's customer. To us, this seems inequitable, because RMR contracts, the units were installed as a cost-effective alternative to transmission, and those RMR units are need to support reliability of the grid. So, to the extent that we really need to have RMR contracts, we think we need to take a really hard look at how those costs are spread to customers. With that, I'll conclude my remarks and address questions at the end.

MR. COLEMAN: Thanks, Judy. We'll turn next to Keith Casey from Cal ISO. Keith?

MR. CASEY: Thank you, Mr. Coleman. I'd like to, first off, thank the Commission and Commission staff for holding this conference. It's a pleasure to be here to provide California ISO's perspective on this very important issue. It's extremely important to California as we move forward with our new market design.

The disadvantage of going so late in the day is that it's hard to be original. The advantage is, it is an opportunity to build off of some of the comments I've heard from the previous speakers.

Several points have been made today that I agree with, and I would like to reinforce them, and there have been some points that I don't agree with and would like to explain why.

We heard a lot today about getting the prices right, and there are a few points that I would like to make about that. I wholeheartedly agree with Mr. Bowring from PJM that, absent physical scarcity, the correct price is the unit's marginal cost of production. I think that's a standard that most economists would agree with.

I wholeheartedly agree with the concept that you can have market power problems in load pockets, but not have scarcity. You can have an abundance of generation, but it's owned by one generator owner, and they are able to exercise market power, so you need to discern true scarcity from market power.

We support the concept of physical scarcity in developing pricing rules during periods of scarcity. In fact, our proposed ND02 design actually does have an element of scarcity pricing. Some of the concepts proposed today relating to scarcity when operating reserves drop below a certain level, perhaps has some merit, but I think there's a lot of things that need to be worked out to really iron out whether that approach has merit.

High prices or the threat of high prices are necessary to incent new generation. We've heard that a lot today. The story basically goes that load-serving entities aren't going to enter into forward contracts unless there's the looming threat of high prices, if market conditions deteriorate, and, as you heard today, suppliers is not going to build new generation unless they have the ability to do forward contracts.

I think this concept makes a lot of sense when it's applied on a regional basis where entry is relatively easy. Entry does not necessarily have a significant impact on market prices. Where I think that concept falls down somewhat is in highly isolated load pockets where entry is extremely difficult and where entry, to some extent, will have an impact on reducing market prices.

It may lead to the type of market failures that Mr. Hogan spoke of. Again, the concept of the need for high prices to attract investment, it can work on a broad regional basis to address regional needs.

We don't think it's particularly applicable in isolated load pockets, so if high prices in load pockets are not the answer, what do you do to ensure adequate infrastructure in lieu of profits? I think the answer to this really lies in getting straight, who is responsible for reliably serving load?

In California, that obligation lies largely with the utilities, the major load-serving entities in California. And when you think of it, local scarcity is a reliability problem. Scarcity and reliability go hand-in-hand. In fact, as we sit here today at this conference, some 3,000 miles from here on the West Coast, there are a bunch of people in a PUC hearing room, discussing transmission projects for San Francisco, and the need for those transmission projects.

And in those discussions, they're debating the merits of a new transmission line, relative to building new generation. The impact, environmental and social, of building that generation, whether to retire older, less efficient barrier units, whether you can avoid all of that through energy efficiency programs, demand response, my point is that in load pockets, the issue of providing the infrastructure is a huge public policy issue with large social and environmental implications, and it's a very long and timely process.

MR. CASEY: So, the main piont being that given in that context is having high prices and load pockets gonna help bring about the needed infrastructure and I would argue that, if today that debate was happening and the prices in San Francisco were $1,000 every hour, those prices would in fact detract rather than help bring about this needed infrastructure.

Again, ultimately, with respect to infrastructure and load pockets I believe it is a local resource adequacy problem best addressed by load-serving entities.

So how do you get, how do you get the infrastructure in the load pockets? The best approach is through long-term planning, through long-term capacity requirements.

And the recent order issued by the PUC, while not all that we would have hoped, at least from the ISO's perspective does provide a framework and something to start from in terms of defining locational capacity requirements and incorporating those into the utilities procurement plans.

The key there is to address local market power problems, simply shifting an energy market power problem to a capacity market, moves the market-power problem to the capacity market.

I think that process needs to be forward-looking enough several years out so that there are a lot of options that the load-serving entity could enter into to mitigate the local market power concern. So I think there's promise and potential for load-serving entities, through the procurement proceedings at the UC to meet local reliability infrastructure needs. That's the best venue for it.

Again, just to quickly summarize the high LMP's and load pockets are not really the solution. We favor very aggressive mitigation for energy bids in local market power situations. Scarcity pricing has merit, but more work needs to be done to define where, how, and when scarcity pricing takes place.

Most importantly, when you have aggressive local market power mitigation, it's critical that the units in load pockets are able to recover the full fixed cost. Ideally we think long-term contracts with the utilities is the best way to address that.

But ultimately I think RMR contracts do have a role in the future design as a backstop in the event that the contracting doesn't occur or certain units are missed to make sure that we are able to catch and provide the revenues necessary for those units to recover their cost.

My last comment: The worst solution from the local market power standpoint is to incorporate fixed cost recovery through bid adders to the variable costs of units as part of mitigation. We think that's a very imprecise tool that is most likely going to lead to certain generators getting way more revenues than they need to recover their fixed costs and others not getting enough.

With that I conclude and look forward to your questions.

Mr. COLEMAN: I appreciate your comments, Keith.

We have next a man who has been very busy doing his own stakeholder process. He's out in the Midwest ISO. We have Ron McNamera, Vice President, of Regulatory affiars and chief economist at the Midwest ISO.

I appreciate your taking the trip here to be with us today.

MR. MCNAMERA: Thanks again to the Commission for asking us once again to represent the MISO and our budding market out there.

I apologize I wasn't here earlier. So maybe I missed some things and I will be redundant. I didn't have the benefit as Keith did in terms of -- and I'm sure I'm going to reiterate some of the points they made.

I'd like to start by saying I'll take as a given that everybody understands the importance of getting the market design correct, that we do -- actually having gone down many different pathways and many different intellectual excursions that we do pretty much have a good idea as to what works and what doesn't.

And I think that has to form a fundamental basis for any mitigation plan that we actually have -- a robust market design that underpins that and lays the foundation for that. By that I mean basically centralized, security-constrained economic dispatch relying upon LMP.

I think when I hear terms like "in the market" or "be in the market" or "out of the market," that's where question marks start to come in the back of my head. You can be in the market. You can be out of the market. But you're always going to be a dispatch.

And there's always going to be an LMP price produced. And the price is going to bring transparency and it's going to fundamentally link the commodity to the delivery side of things, which is so vitally important to getting the signals right all the way up and down the chain from the forward markets into the real time when the product actually goes physical.

It would be great if electricity had some kind of better storage properties so that we could kind of have a gas market type of thing where we could really separate delivery from the commodity. But we don't.

Electricity doesn't behave that way. And so linking the delivery mechanism to the commodities is fundamental to the new market design.

That being said, I would then like to diverge a little and say from the economist's standpoint when I look at market power, really I look first to a commercial solution.

Why can't we get a commercial solution in this situation? Usually what you get back is well, I can get a commercial solution. I just don't like that commercial solution. At least one party says that.

I think where we then end up is we don't actually evaluate essentially the economic properties of that solution vis-a-vis the alternative properties in terms of -- by going down and recommending increasingly onerous mitigation procedures. What are the kind of welfare properties that result from those in terms of a long-term investment and consumer behavior? and so on and so forth.

And I think it will be useful to essentially have some sort of test. We've actually looked -- we're already in this world of second best. Which is the worst of the two? Which is the best of the two? Really if you look at it from the standpoint of a commercial solution and you kind of take that line of thought, then you go down the path of, well, really market power represents a loss or manifests itself as a loss of leverage by one of the parties.

Really what's happened is choice is restricted; the options aren't available. And that really in effect reduces leverage that one party has due to negotiation.

Really what we should be looking at for the long-term solutions, I'll echo the sentiment that John Meyer made earlier in terms of short term versus long term.

Is this a temporary problem? Or is this a long-term problem? I think the greatest welfare game from eliminating this over the long term as opposed to the short term.

What I'm addressing more is, what's the long-term solution to this? And in effect how do we increase the leverage that parties have so that it's somewhat symmetrical in this. And then we have to define that path at the beginning.

One party has a loss of leverage. What's the part cost of whoever increased their leverage and who pays to increase their leverage? I think that's where we have to ask the question of what role does market design play -- i.e., price caps and RMR contracts and so on and so forth. How does that in the long run actually increase the leverage the other party has?

I guess what I'm alluding to here is the fact that market power is in some ways very difficult to define. I do believe we have markets where there's monopsonistic power. We tend to focus overly on the sellers' side as opposed to the buyers' side. I think that's something that needs to be looked at.

I also think we have to recognize that there is a fundamental problem. It's not a bad problem. It's just a real problem. And this is you have assets going in the ground that are essentially making the long-term decision 20, 30, 40 years out. And you have buyers that are buying short-term every single day.

You have a problem as there the supplier is supplying long and the buyer is buying short. That's going to create essentially a disconnect there. And I'm not sure how price caps necessarily resolve that problem.

They may resolve it in the very near term. But this gets back to what I would criticize in that there seems to be an infatuation with the spot market when in fact the spot market, as almost any mature electricity market, represents a minority of the sales, not a majority of the sales.

With that I'm going to use my time and turn it over to my stakeholder.

MR. COLEMAN: Thanks, Ron.

Our last speaker on this panel is Steve Beuning from Xcel Energy. Thanks, Steve.

MR. BEUNING: Ron, you took that right down to the last second. That was perfect.

I'm with Xcel Energy, one of our operating companies. Northern States Power is located in the Midwest ISO footprint, so it's my pleasure to work with Ron. It's also my pleasure to be here with a chance to talk to you all.

We have a generating station in northern Wisconsin on the south shore of Lake Superior that's necessary to be on line and in peak periods to prevent a blackout from loss of a transmission element.

That area reliability that it supplies has to be there about half the hours of the year. So this grid operating guide compel us to put this unit into the dispatch mix out of merit order.

Does that generator have market power? I'd say I haven't given you enough information yet to conclude that because you don't know if I'm putting the costs for that generation onto some other party in an inappropriate way.

As long as it's all my own load in there and it's all my own generation in there, in that load pocket one could argue that that's not a situation that would even be applicable for a market power calculation.

I wanted to just get right to the summary of my points. Then I'll digress back into some of the detail given the late hour here.

But I guess in the long run the development of transmission facilities that are economically efficient and environmentally acceptable would increase reliability.

If you had a load pocket, it would expand the pool of available resources to supply that load. It would increase market access for generators who reach those loads.

But until you've solved that problem in that way -- and by the way, if you did solve the problem in that way, you'd be allocating the costs to people through transmission rates.

Until you've solved the problem that way, you've got a situation where generators that are critical to long-term good reliability should be getting compensation that meets some principles.

The compensation should be no less than something like the greater of the regional market clearing price or their own long-run costs. Plus there should be a consideration for the value of the transmission deferral that that generation operation has made possible.

In the load pocket we've got infrastructure lacking by definition. It's just unreasonable that the financial support to the generation in that load pocket should be commensurate with the infrastructure requirements to serve those loads.

And we shouldn't be scaring investors and operators away from that load pocket with the threat of price mitigation. That valuation of the transmission deferral could be performed by the RTO as part of a regional planning process.

The additional consideration provided to the generating units perhaps could be based on that. We've got cost allocation in this part of the discussion and maybe we'll want to talk about it a little bit more.

Now, maybe we're talking about something that's not getting cross-allocated as part of transmission rates. But if we're given the fact that this unit is necessary for reliability and that that's going to be increased costs over the basic market-clearing price, how do we spread or allocate those costs?

If I start with a load pocket definition like this, it's an area of the grid where a binding transmission constraint requires generation in the local area in order to maintain post-contingency delivery to loads.

And then I just wanted to add a distinction. I think a load pocket is not the same as a generation pocket, which I don't hope we address today because a generation pocket presumably would be something solved through order 2003 implementation in the future.

I want to talk for a second about how we did it in the old days. We used to administer our network tariff at Northern States Power that was pre-RTO. In that situation we took the costs of redispatch and allocated them to the parties to the network tariff.

We had something like a local uplift phenomenon. But I would submit to you that in the case of a large regional network tariff that would not be an equitable situation for the following reasons. The uplift costs could be incurred in the area of the grid where the party paying the costs has no voice in the planning, construction, or operation of the grid elements.

The parties being uplift can't rationalize those costs as a trade-off against their own costs of transmission construction.

And there's too much lag between the point in time that you identify the problem and the transmission construction solution.

So if we're going to allocate the cost under the RTO's network tariff, what are some of the things we might want to think about?

We might want to have identification of load pockets bubble up through -- lie along between the reliability authority, the grid operator, and the regional planning process.

We might want to stipulate operating response for a generation in the load pocket in public documents as parties' operating procedures that recognize that plant output is variable and the plant availability is not to the same degree as transmission facilities' availability. We try and identify and develop those costs on a market basis to the extent possible.

I do think that for long-term load pocket problems we could be fairly precise in the identification of those areas as part of the regional planning process.

Let me skip around because I'm out of time. I guess if we get the planning right, I think we'll be able to follow the cost allocation properly in the long run.

And I just wanted to reiterate that I think -- Virtune recognized that supporting costs for a generation in load pockets is a more valuable service than just the generation cost because they've got that avoided transmission investment and increased reliability in the area that's making it possible.

I'll cut it off at that. Thanks.

MR. COLEMAN: Thanks, Steve.

I have a question for Keith. If I heard correctly, you were saying that the market design and the spot prices that this Commission is responsible for you think should not really reflect scarcity and some of the high priced aspects that we heard about this morning in the California market design, but rather await the state resource adequacy approach and allow that to take care of the problem while we sort of mitigate the price signals that would otherwise be coming out of those areas if we followed the principles being discussed this morning. Is that correct?

MR. CASEY: With respect to whether you'd allow any scarcity pricing in a load pocket, our MDO-2 - for those of you not familiar with our vernacular, our new market design for California, our LMP market design -- does propose that if there is truly a physical shortage, that there's insufficient supply to serve load, that prices would be allowed to rise to the price cap. In that context the design does allow for scarcity pricing.

What we've not contemplated under the design is what Dr. Patton talked about -- scarcity pricing. If operating reserves in the load pocket drop below a certain level -- again, that's a relatively new concept that I think needs to be flushed out of it more to understand how you can implement it in the context of the design and how frequently it would be hit.

The big concern we have is because of the extensive time it takes to develop infrastructure in highly concentrated load pockets, whatever scarcity pricing mechanism we have, if it's being applied every hour for several years, the dollars are going to start adding up.

I think you have to be cognizant of the fact that there is a much longer planning horizon for meeting local infrastructure needs than would be the case on a more regional basis.

MR. PERLMAN: I'm really asking a different question, sort of a macro policy question. I read your MDO-2 filings. I'm familiar with them.

I got the sense you were saying that a lot of RMR contracts -- we have the CDWR contracts. We have other things that take these power plants effectively out of the spot market. And you used the three percent transacted through the spot market in your filing.

What I got from that was, don't worry about getting the market right because it's really not that important if we're going to allow the other aspects of the market to work. So let's just keep the prices low in the spot market and let's address the spot market as sort of a balancing market.

Is that a mischaracterization of what you've filed?

MR. CASEY: I think it's an incorrect interpretation of the arguments we made in that filing. We're arguing that mitigating unconstrained areas to unit's marginal cost is getting the prices right. Because in our view allowing prices to go above those levels, absent physical scarcity, I don't understand the economic rationale for that.

MR. O'NEILL: In order to qualify that, you said physical scarcity. Does that include operating reserves? In other words, if there's physical scarcity of energy plus operating reserves, would you consider that a physical scarcity?

MR. CASEY: That's an issue we would have to take a look at. As I have said, with respect to if there's truly insufficient supply to meet load, you're having to curtail load.

MR. O'NEILL: I would think that NERC would consider that a physical deficiency.

MR. CASEY: We would agree. When you talk about operating reserves dropping below a certain level, that gets into a grey area in my mind that we would have to take a closer look at to see if that's a viable approach.

MR. O'NEILL: It's not so grey for reliability.

MR. CASEY: That's true, but reliability isn't black and white. There are variations of reliability risk and whether that's truly physical scarcity.

MR. SINGH: Stage 1, 2, and 3 -- all of them are not on the table for scarcity pricing I guess.

MR. CASEY: As it's proposed in our design, that's correct. I'm not ruling out the concept of applying scarcity pricing if reserves drop below a certain level in load pockets. It's just simply one has to look at how you would implement that approach and what are the potential impacts of it in terms of how frequently do you bind in.

MR. O'NEILL: Isn't that a good signal for load, when you're in one of these reliability stages that sees the price go up?

MR. CASEY: I think the most important signal for load is that you have a regulatory obligation to keep the lights on to serve load.

MR. O'NEILL: We would love to see that happen, but we're not sure it will.

MR. BANDERA: Keith, just to maybe jump in, would you say that you might agree that an operating reserve shortage is a physical shortage, but in terms of scarcity pricing as you jump right into MDO-2, you might be more concerned that the cost shifts that occurred before any needed investment could come in could be overwhelming and you would prefer a type of mechanism that would be phased in over time? Or do you think that it would never be appropriate?

MR. CASEY: I would say -- and again, in terms of representing the ISO's views, I can only speak to what we filed in our design. That said, I'm offering this on this issue.

I would certainly be open to evaluating a scarcity pricing under an operating reserve threshold. But there's a lot of information we would have to develop on how that would work and the sensitivity to the fact that you'd have to recognize that meeting infrastructure needs in densely populated areas is a very slow litigious process. And you have to design your policy.

MR. BANDERA: One last thing. Before your opening remarks you made a comment stating that sort of reliability was the state and the local utility's responsibility, not necessarily the ISO's responsibility.

Earlier today we heard comments about wholesale market design rules. Should we stand alone in a sense and not be held captive to sort of retail structures that are in place on a state-by-state basis?

Do you think that there should be a sort of a case-by-case basis on the retail structure and how the reliability of each is responsible for the terms of designing those wholesale market rules? Or do you think they need to do it independently?

MR. CASEY: I think there has to be some flexibility and deference to, you know, regional wishes in terms of the scope and scale of the RTO's functions, particularly in the area of resource adequacy.

You've heard Mary Strongly from California that they view resource adequacy as a state issue. I don't know if that answers your question.

MR. TIGER: I'd like to ask a question of Mr. Meyer with regard to maybe a little bit of a clarification as to the exit strategy option -- whether you could expand a little bit on that.

MR. MEYER: Okay. The exit strategy we had in mind -- when we're talking about exit strategy, the exit strategy option differs a bit from the PJM proposals they described earlier this morning.

Their decision is more what I call looking ahead or a transmission planning. Or a network design type function is you look ahead and there's inadequate capacity to serve the area reliably. You either bill transmission or create an auction to entice new generation if you're not sending proper price signals. What I was talking about is, for instance, as Keith just mentioned, his view is that you only pay marginal costs to generators in a load pocket for providing a service. I stated you should pay well above marginal cost -- just make sure that you have enough money to stay there.

But if you pay marginal costs, it's a political or policy decision, but you've got a lot of -- but you can't say I'm only going to pay your costs. You may not recover your needed revenues. But you're going to stay here anyway because basically you're creating an obligation to serve.

What the auction tries to do is two things.

While you're leaving for reliability, it tries to immediately find the outcome that's most efficient -- number 1 -- which could be transmission generation or load.

Number 2, it tries to value what that's worth. As someone suggested, you should pay part of that because that's really part of the rent, that extra value that unit may provide to that area.

We believe that auction does those two things. It values the avoided costs for what service costs you're providing, number 1. And it finds the most efficient solutions. So that differs where I'm reliability short and I must do something such as build transmission.

MR. TIGER: You're basically finding out the value of the opportunity cost or the fixed cost essentially through some process and that's administered presumably by an independent party.

MR. MEYER: I'd say an independent party. To me it should be probably the RTO or ISO. But we want to make sure he has an independent view of that. It shouldn't be biased in any way.

MR. COLEMAN: John, does that give you the opportunity to go into those markets where you say I want an exit strategy?

If we were willing to pay you your long-run marginal cost, you may say, well, we'd like to have someone evaluate what, I guess, the replacement infrastructure would be to you. And if that's higher, aren't you holding us hostage in terms of saying, well, I'd like to get that high a price even though --

MR. MEYER: If you're paying me my long-run marginal cost, I'm not sure why I would suggest I'll retire.

MR. CASEY: If I could just add to that. John picked up on the first point of my statement, which is we believe the short-run marginal cost is the right price signal absent physical scarcity.

But the second point was that absolutely units that are critical to providing local reliability services need to have their going forward fixed costs covered. And the best mechanism for doing that is a long-term locational capacity obligation.

We weren't suggesting to strand units without adequate compensation.

MR. PERLMAN: I have a question on that retirement option. If you're going to retire the unit -- I guess, if you're going to exit the market, someone is going to come in and take your place if there's reliability concerns. And there will be a transition period I assume.

MR. MEYER: They might.

MR. PERLMAN: As soon as you're free to exit the market, you don't want your asset anymore. Would part of that offer of exit be that you would make your existing asset available, let's say, at book value for others to take over if they were to come in and replace you and do some sort of reliability project? So therefore you wouldn't have a leg up. Everybody's competing on the same place.

MR. MEYER: I think you've asked me this before in other forms.

(Laughter.)

MR. PERLMAN: But not in a public one.

(Laughter.)

MR. MEYER: We have cases -- I believe a plant in California -- where the market value of the land exceeds the book value probably by 10 times.

MR. PERLMAN: Let's say a higher book or market value.

MR. MEYER: I think they would probably sell that. I don't know why anybody would just walk away from it and make a rational business decision. But they will exit the market if they can't sell it.

If you can't earn the money, I'm not sure how anyone else can earn the money. But yeah, I would sell it for an adequate value. No reason not to.

MR. TIGER: Would Dr. Newman care to buy it? I guess maybe you could talk a little bit to the degree of which now you've had the benefit of some of the conversation about what the necessary conditions would be for you to invest in generation.

MR. NEWMAN: I have two minutes saved up, right?

(Laughter.)

MR. NEWMAN: Sure. I listened to this conversation about mitigation and in part it makes my blood run a little bit cold. I would refer to that as the "theory of the second yes" rather than the "theory of the theory best."

You're asking somebody who comes in here to put his capital at risk whenever markets tighten up, which will take away the opportunity to earn a return on that. I think that's difficult.

So the short answer to your question is, if you're asking me to rely on volatility to get paid a return on capital, I find that a very uncomfortable situation. And I listen to this conversation and it's all focused in terms of well, when prices exceed your marginal cost, that's a bad thing.

And I keep asking myself, isn't capital a marginal cost somewhere in here. Why do I get my recovery of my capital? I'm investing on behalf of pension funds. They're expecting me to produce a return for them.

If the only thing I want to get back is my marginal costs at some point, I'm going to be looking for something else to do. And I find that a pretty uncomfortable position for us to be.

So I think a focus on volatility is an uncomfortable place for us to be. It makes me much more comfortable, so I would buy John's plants, but I need some sort of contractual protection there for the capital.

My reaction is if you look at contractual capital, you can get long-term capital and long-term capital tends to be much cheaper than short-term capital because you can recover it over a much longer period of time.

In fact, I've always found it interesting -- this focus on relying on volatility to recover capital costs -- because it forces you to attract capital who is comfortable getting that kind of return, which tends to be very short-term, high return capital, the stuff that trading desks do, not the stuff that institutional investors do.

The short answer to your question is: I don't like relying on volatility to buy Mr. Meyer's plant. And if you were to offer it to me in a world where I was constantly being mitigated and reduced to perhaps my energy margin, there's a price I would buy it, but it is unlikely to recover his market or capital costs.

MR. BANDERA: It sounds like both the sellers of energy don't want to see volatility. They would like to see some more certainty. And the buyers would like to see more certainty. And that when you have this spot market regime with the volatility, it seems to give both of those people the incentive to work together to eliminate that volatility.

MR. NEWMAN: My understanding -- there are some regulatory and other issues with that in some circumstances if the buyer is contracting long term and they guess wrong, they are penalized for it.

There has to be some recognition of the insurance and other aspects, whereas you've talked here that you view reliability as a product. It ought to be priced as a product in that regard.

I think the economists like volatility, but the marketplayers don't.

MR. CASEY: One point of clarification. I wasn't suggesting in my comments that prices during nonscarcity periods should never exceed the marginal cost of units. My point was that price should reflect the marginal cost of the highest cost unit needed to serve load in that.

It would certainly be the case if we had a brand new highly efficient combined cycle, that the prices being set by a 40-year-old coal unit -- there are some infra-marginal rents that your efficient unit would be able earn.

MR. NEWMAN: Whether those are sufficient or not?

MR. CASEY: Whether those are sufficient to cover your fixed costs is a valid point and that's why in my view you have to supplement that type of mitigation with an opportunity through a capacity market to acquire additional revenues.

MR. O'NEILL: If we don't let the spot market clear properly, how can we evaluate whether or not the resource adequacy, which is a CPUC decision, adequately compensates the generators?

MR. CASEY: In the case of California, we're not proposing a formal long-term capacity market. What we're proposing is that the requirements be established by the Public Utilities Commission working with the utilities. Then they would contract bilaterally to meet those needs.

In that case each party would bring to the table their respective positions. If they strike a deal, then the generator entering into that agreement voluntarily -- you'd have to argue I believe they can recover their fixed costs with that capacity payment.

MR. O'NEILL: But how do we know that? Are we going to ask you to file all those contracts so we can read them?

Shouldn't it be better just to make the spot market clear properly and the people who are long and have contracted long benefit from the spot market prices if they are high? And if the people who are short and told us that they are really long see high prices, then it's because they thought they were long and they weren't.

MR. CASEY: I guess the question is, should we let the spot market clear properly? If that means don't apply local market power mitigation, let the prices be what they will. I don't see how that --

MR. O'NEILL: It's local market power mitigation with appropriate scarcity prices.

MR. GRAMLICH: In terms of what an appropriate price is, Danielle mentioned an interesting case in ERCOT where additional supply came on and the price went up. Is that what you'd see in a competitive market? You wouldn't see that if you had scarcity pricing.

MR. CASEY: I don't see how in a load pocket you have additional supply committed to that market.

MS. JAUSSAUD: This is a generation pocket. That's why the price went up.

MR. GRAMLICH: In PJM I was -- maybe ERCOT is designed just fine. I was going to say this happens not just in ERCOT, but it does happen in PJM and elsewhere. If the price-clearing mechanism is the generator's supply bid at all times, then you can have a situation where increased supply raises the price, which is not what is supposed to happen.

MR. CASEY: I don't see how that would happen unless you had some other lower cost units that became unavailable.

MR. BANDERA: I could come up with an example for you. I start a little wood-burning stove plant in San Francisco. Then when you're in an operating reserve shortage out there, I put in a bid for $2,000.

Let's just say I've got a megawatt here that I can put out for you and then secure an operating reserve shortage situation. You need to take my energy so that you can keep as much reserves as possible.

So before they may be in a load pocket, their marginal cost was only $250. I've got my unit in there that has a marginal cost of $2,000. My entry of just one extra wegawatt at $2,000 has increased the price from the mitigated price level at $250 to $2,000 by adding extra supply, because before we were mitigating to the marginal costs of the unit even though we were short operating reserves.

MR. CASEY: We'll have to follow up on your example.

MR. PERLMAN: Can I ask Mr. McNamera a question?

I heard Mr. Beuning say earlier that in his company and in MISO to some degree you're going to have situations where you have a vertically integrated utility that hasn't disaggregated that's part of the MISO that have load pockets within its service territory, where it has generation load -- both.

Is it your view that if it's a vertically integrated utility with retail rates, that it's part of the MISO market that the Commission and the MISO should still undertake with you of that load pocket and do mitigation with respect to the units in that area? Mr. Beuning indicated in his view that that was questionable.

MR. MCNAMERA: I think you have to look at it, because there are going to be off systems sales. There's going to be all sorts of things that are going to happen. I think you have to take into consideration who they are selling to and so on.

But I do think it has to be part of something.

MR. BEUNING: If you define that load pocket as that area that's got the binding constraint and needs the generation inside, if there's exports happening out of that load pocket, then the generation in that load pocket must be a marginal unit.

So in that sense I don't know that you could assert that they had market power.

MR. CASEY: I guess I would add if they are exporting, then you don't have a local market power problem.

MR. MCNAMERA: The question is interesting to look at. Yes, it's got to go through. You don't just ignore it.

MR. PERLMAN: I guess there's a different question of whether you ignore it or not. It's a question of is there something different about the MISO structure because of the existence of vertical integration.

That's different than other markets we're talking about -- that calls us to consider it differently or should be considered in the same manner and to just go forward with a structure that looks similar, say, to New England.

MR. MCNAMERA: So the lack of retail choice in the MISO states necessitates.

MR. PERLMAN: Not retail choice, but an example we talked about. You have load and generation owned by the same entity that's serving in effect retail at the end subject to state regulation, so you don't end up with much that's transacted through the wholesale market.

But you could have some price signals you want to send or something like that that may cause you to recognize it as a wholesale market issue.

In the example we talked about the power isn't being exported. It's being run by a local generator to serve local load and is basically subject to the local commission.

MR. MCNAMERA: It has to be contingent on the fact that basically the buyer and seller are the same company. So it's one company.

MR. PERLMAN: Which I think is not unusual.

MR. MCNAMERA: That may not be unusual. Let's wait and see what the flow patterns are after we start with LMP. I know that those are the flow patterns that may exist today, but I think when you get transparent price signals, there's not a market that's gone to LMP that the flows haven't changed dramatically.

MR. HELMAN: Ron, let me ask you ask another question about MISO. Since MISO is going to start as an energy only market, you all have the chance to apply locational reserves or a locational capacity at least initially.

Have you looked at whether the New England experience with loosening mitigation at the load pockets -- that didn't work at least initially in that summer and may not have worked under many circumstances. Have you looked at how that might affect the particular load pockets that you have -- i.e., whether they are likely?

We heard that there wasn't sufficient market power in the load pocket in New England to get the prices up to where they are needed to be. You're going to be working only with the energy prices. Have you looked at those sorts of effects in the other load pockets?

MR. MCNAMERA: It's hard to look at it before you get to LMP -- I would say number 1. But I do think we're in a different situation. We do have areas where we have severe constraints. And it is likely that we are going to run into -- that the prices will rise considerably if left unfettered.

LSE has been one of the stakeholders involved in this. We do include the effects of reserves on dispatch. And while there is a reserve market, certainly reserves will essentially be explicitly incorporated into the dispatch and will be for added effect.

MR. HELMAN: But you won't be able to get a locational reserve price or have a reserve price transferred to the energy market.

MR. BEUNING: Can I try and answer this one quickly? While the operating reserves taskforce of stakeholders was meeting at the Midwest ISO to try to establish how things would be handled in the transition into the full blown market design, we did recognize that there's currently self-provision of the requirement from road-serving entities.

Through the participation of those LSE's in their regional reserve-sharing agreement, the sharing agreement sets aside the transmission reserve margin, TRM, and also establishes the requirements for how much reserve each party is obliged to carry.

So at this stage even if initially the Midwest ISO's market were to start on the first day of day 2 with a contingency reserve market, absent some decision by the market participants who are currently self-providing through this grandfathered regional agreement, there would be no clearing in that market because they are already meeting that obligation.

I don't know if that addresses the issue of how you identify scarcity of locational reserves. But I'm not aware of a mechanism today whereby there's an explicit process for establishing a requirement for locational reserves in the MISO footprint.

MR. HELMAN: That was my point. I guess some of the things we heard earlier were that New England, the failure of the push mechanism, which was an attempt to loosen the mitigation, the next steps in that would be to have a locational capacity requirement or a locational reserve requirement.

That was the direction the market design solution is going on the East coast. That's not available in MISO. So you're basically in a push-like situation.

MR. MCNAMERA: I think there is general acceptance to a greater or lesser extent across stakeholders -- certainly the MISO -- that we will move in that direction. We don't think we need that in order to arrive on December 1st.

MR. SINGH: You briefly mentioned that you were going to rely on LSE contracts. The conventional wisdom is that the prices in these contracts are a function of the spot markets. With the mitigation there they are going to have an impact on the compensating ability of any of these contracts.

But I would think then that maybe that changes if you mandate long-term contracts. I don't know if you think that's important. Does it introduce a disconnect between the spot market and spot markets and market power and some of the long-term contracting?

MR. CASEY: I'm not entirely sure I understand your question. You're saying if you mandate long-term contracts for load-serving entities, would that create a disconnect? And what those contracts would be valued at relative to the spot market if you didn't mandate it?

MR. SINGH: Yes, because if I'm an LSE and I can go between spot or forward, then, you know, if one is mitigated, then I would go there -- if the center is exercising market power in the long-term contract. But if you as a regulator come to me and say you have to buy all of your energy, 95 percent or some reserve margin long term, then it's almost like it's a regulatory requirement. So then you could have sellers charge prices that are not necessarily a function of the mitigation of the spot market.

I was just wondering if that's correct.

MR. CASEY: I think it's important to keep in mind that the contracting requirement doesn't necessarily have to be for energy. It could be. Ideally you'd want the flexibility to provide a mix of capacity contracts and long-term energy contracts so you could make that trade-off.

I want to make sure I have sufficient capacity to meet load three years from now, but it doesn't make sense for me to buy 100 percent of my load requirement at that point. So you could defer some of your price risk to the spot market, but you'd have to procure all of your capacity requirement.

If, by forcing a requirement on load-serving entities, are you creating a market power problem? The comments we offered -- because this issue did come up in the PUC proceeding -- is that as long as you're looking out long enough, several years or more, the load-serving entity has a lot of options, because you're looking at building new generation transmission so the market power issue then becomes much less of an issue.

MR. BANDERA: Keith, can you explain what capacity means in the context you just mentioned? You can have a contract with capacity. I understand in the Northeast ISO's, there's capacity that's subject to mitigation and all that.

In the context that you're talking about with these bilateral contracts between parties what does it mean to procure capacity?

MR. CASEY: I think it would have the same implications. If the load-serving entity had a capacity contract with a supplier, the supplier would have to offer that capacity into the day-ahead energy market and there was a requirement that it be offered at a fixed price or perhaps the contract said I'm not going to require a fixed price. You are free to offer it at any price. I just want that capacity to be there and bid into the market.

So I think it could work the same as it does in the Eastern ISO's. It's just through a bilateral mechanism.

MR. BANDERA: It's not a bilateral mechanism just where they're providing capacity to one LSE solely. So it wouldn't be the generator is obligated to provide capacity to the LSE and not to the market as a whole. Is there any distinction?

MR. CASEY: That's certainly the way the ISO views the capacity obligation should work. It should be made available to the spot market because ultimately you want to optimally dispatch that capacity.

I know in the context of the PCU proceeding that was an issue of concern by a number of parties. If I procure this capacity, I don't want it serving somebody else's load.

So I think that's an issue that we'll have to work through in some of the workshops that the PUC is planning to hold on how you count capacity going forward.

MR. O'NEILL: Is the reason why they don't want that capacity serving someone else's load is because the spot market price is potentially too low?

MR. CASEY: I'm not prepared to speculate on the rationale for that particular position.

MS. SHIPLEY: Can I just ask -- we heard earlier from a load-serving representative from New York, who was saying that New York City is a load pocket and they have high prices. And that seemed appropriate to him.

MR. CASEY: I guess it again comes down to the issue of what do you believe during down scarcity conditions a competitive outcome would be.

I think the argument is the reason you're mitigating in the first place is because you believe there's a market power problem. So the way we approach it is, then what should you try to accomplish by intervening in the market mitigation?

Our view is to try to simulate as best you can, albeit imperfectly, what a competitive outcome would yield. And in our view that's the marginal cost of the highest cost unit.

Now, the New York ISO has contract and impact thresholds that essentially allow an acceptable level of bid markup. But with all due respect, that's an acceptable level of market power.

An argument is, well, those excesses can go to fixed cost recovery and that's certainly true. But is that a perfect instrument for providing fixed cost recovery?

And our argument is it's very imperfect. With that type of mechanism there are going to be some resources that are able to over-collect in terms recovering their fixed costs. And there will be other resources where the threshold is not high enough.

MR. O'NEILL: There's more than one explanation for the flexibility that AMP allows. And one of them is your inability to get marginal cost right exactly.

And I think, as Bob Ethier pointed out, in New England the last couple of weeks, trying to get the spot market price correct to put into your marginal price calculation, you could have been off by a factor of two without even working hard.

MR. CASEY: I certainly agree that trying to estimate the marginal cost of unit is an imprecise science. There's no question about that.

The reason we proposed the 10 percent bid adder similar to PJM was to try to capture some of that. And I'm sure some would argue that's not enough.

MR. BANDERA: Would market design rules be different for generators that aren't in any long-term bilateral contracts where the mitigation rules?

MR. CASEY: We're not proposing different rules depending on supplier's contract positions.

MR. SINGH: I just want to ask one last question on something Judi said. You said RMR contracts are causing prices to be higher. Is that more a consequence of how they are being used? Because if they were actually being used, I would think the prices would be lower because of all of the energy that would be in the market.

MS. MOSLEY: I think that's right. My comments were directed primarily to the condition 2 contracts. Also the fact that RMR is used more in northern California than it is in southern California. In southern California they found other tools to rely upon in order to mitigate, including the must-offer requirement.

So my comments -- I'm not suggesting that RMR contracts generally have no place at all. I think they are still necessary, particularly for older, less efficient units that would not be operating in the absence of a contract. We'd have serious concerns with the condition 2 arrangements.

MR. O'NEILL: As I understand, the way you describe the process, the RMR, costs get assigned directly to PG&E. And the transmission upgrades get assigned to the camp and the whole California foot-print. Why aren't you building more transmission?

MS. MOSLEY: We're doing that too.

MR. MEYER: Could I just add a clarification? I keep hearing or heard that RMR or fixed costs should not go at all into the LLP. I'm not sure I really understand. It seems to me like the best way to get the proper price signals is to include some of the fixed costs in these areas and to the LMP as opposed to giving RMR contracts.

I mean, we've already gone down the road, particularly like in PJM, of the co-cost approach. Even that oftentimes you could look at different units -- and particularly the ones I'm worried about are the ones that are small GT's, small load pockets.

I don't think capacity markets work with a load pocket of one or 2 units. And if you locally run 2 or 3 percent of the time 200 hours a year, if you look at their O&M cost, it's going to fall in a range between $10 a kW to $20. That's going to work out from $50 to $100 a megawatt hour spread out.

They are never in the market. You need it. How in the world do you expect for them to recover any money and stay there if you don't know why they put that fixed cost in the LMP?

MR. O'NEILL: As Mike Schnitzer testified, there are four or five cases where you do different things because of the situation.

My own personal feeling is that as soon as we start getting involved in making fixed cost calculations, sunk cost calculations -- and I realize that your O&M is really a variable cost going forward, so that's a different story.

But as we start getting into fixed cost calculations, we're on that slippery slope that people talked about this morning. The cost of service regulation is the whole issue -- that we let you recover your fixed cost in the market and not here at FERC.

MR. MEYER: That's why we proposed other ways to do it. The point is you have to allow enough offer cap. If you're going to mitigate in a load pocket, you have to allow enough offer cap for most units in there or all units to recover their basic fixed costs. If you don't, they'll retire.

MR. O'NEILL: We're not going to let you retire. We need the minimum to let you recover your going forward costs.

MR. GRAMLICH: You've given a good advertisement for tomorrow's conference, looking down David Patton's list of priorities. But an alternative source of economic signals. He said the location specific operating markets would work in that case. Locational capacity markets wouldn't work in that case.

It sounds like you would put number four ahead of number three. Your design next best option would be a relatively loose market power mitigation measure.

MR. MEYER: Determine when you need it. For instance, we move from 10 percent on a lot of those units to a to-go cost -- I think of $40. Ten percent was probably $8 or $9 or $10 versus $40.

The use of those units went down appreciably, which to me indicated the LMP selection, that they really didn't have local market power all the time anyway. So we were mitigating time lines.

And I don't know how to make that clear distinction. I laid out some principles. I don't have perfect solutions to it. But somehow we got to make those work.

MR. GRAMLICH: The other option on here is an RTO option. That's the proposal on the table for tomorrow.

CHAIRMAN WOOD: Let me ask you a question, Danielle and John. You ran out of time to say what the solution is. I was involved in setting up the old solution, so I'm kind of hanging with dated breath to know what the new solution is.

MS. JAUSSAUD: The new solution now under consideration -- it hasn't been adopted that this is what we have on the table in terms of compensation for delivery out of merit when there's not a market solution.

The market participants have discussed compensating at generic costs. But there are various different kinds of generic costs. One proposal was to compensate. And that goes back to what Keith was saying -- compensate all generators, regardless of their resource, at the level of the most inefficient unit in the local market.

We have set approximately a heat rate of 18,000 Btu's. Most of these are gas units. So this would have compensated a new, efficient unit a lot more than an old, inefficient unit. And the idea was that this would attract investments of new, efficient plants.

But this proposal was rejected by the stakeholders because -- number 6 on my list of issues was the price impact was going to be too high for those stakeholders, who were participating in the discussion.

Those who were in favor of that solution were the new entrants through the combined cycles and the RPPS.**

The market participants were looking for a solution that was similar to that but not quite as expensive to the market. And again it comes back to the idea of not compensating the inefficient unit more than the efficient.

They brought a lead to the generic costs of this category, a percentage. One of the ideas was to have a different percentage, a higher percentage, for the inefficient unit and a lower percentage -- I'm sorry, the opposite -- a higher percentage for the efficient unit, a lower percentage for the inefficient unit.

This way the net revenue, which is the total revenue line -- net revenue would be equalized across the board. That was also rejected. I think it was because the formula used was a little too complicated. What is being envisioned now is to have a heat rate adder. If the heat rate is seven, for example, then your compensation will -- your generic costs will be calculated on the basis of a heat rate of eight, let's say.

And that also is considered a formula that would allow an equalization of the compensation and would not favor the deployment of inefficient units.

CHAIRMAN WOOD: How much of the market does this get triggered by? How much of the time does this get triggered in the market? Is it localized to the DFW region or what?

MS. JAUSSAUD: A lot of it is in the DFW region. This is where the most important load pocket in ERCOT is.

The generation that is all around the DFW area is trying to export into the DFW area but can't because of the transmission constraints.

In the example that I cited the new generator was built once again outside of the DFW area in an area where there is generation that would be needed in the DFW area but just can't flow through. That is the problem that's being addressed.

MR. MEYER: I think Danielle's addressing the current solutions as opposed to we're going to an LMP with probably a different approach. We're still probably wrangling over what's the right competitive test to make.

The DFW will almost always be an issue. It's going to be in New York City. In fact it has probably more load, I would say, than New York City. I'm not sure how big New York City is. But I would assume DFW is about 20,000 megawatts. I think that's quite a bit larger than New York City in megawatts.

So it's a big area. As you know, it's totally constrained by regulation. New entry is almost impossible within certain bounds. And transmission.

So there will be some mitigation in there. And I think what's being proposed is more or less a bid cap in the local market pocket. And we haven't set one yet.

So I'm going to talk -- some have talked of a fixed heat approach. Some have talked. We've offered the survey unit approach -- I should say, not widely accepted there.

But given the load there, I can't quite understand it. But anyway, there's got to be some way to handle that. And I don't know.

The proxies I thought Danielle was talking about is more when they do an out of market call. It's a command and control. It's not using any sort of LMP calculation. Of course, I guess we have to roll it into it if we're really going to get LMP.

MS. JAUSSAUD: We probably would not implement LMP until 2007. So we do have to find a solution in the meantime.

MR. MEYER: But we have the same issues everyone else has. And that big a load pocket -- it's quite dramatic.

MR. COLEMAN: I'd like to thank the panelists for spending their time with us giving us their comments. With that, we'll conclude our conference for today. Thanks.

(Whereupon, at 4:50 p.m., the conference was recessed until 9:00 the next day.)